MINI-HYDRO DEVELOPMENT

L'ANSE AU CLAIR, LABRADOR

Feasibility Study

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Feasibility Study

Prepared for:

Town of L'Anse au Clair, Labrador

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With a contribution from:

Remote Community Demonstration Program
of Energy, Mines and Resources Canada

March 1985

RCDP/PDCE-67

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EXECUTIVE SUMMARY

Based on an unsolicited proposal, a contract was awarded to Fenco Newfoundland Limited by the L'Anse au Clair Community Council to investigate the technical and economic feasibility of a mini-hydro development in that area. Funding for the study was provided by Energy Mines and Resources Canada under the Remote Community Demonstration Program (RCDP) and the Community Council of L'Anse au Clair.

L'Anse au Clair, a small community on the extreme south coast of Labrador, is one of eleven (11) communities supplied with electrical energy by a 2000 kW firm capacity diesel generator station located at L'Anse au Loup. It is the third largest user of electricity of the eleven (11) communities, making up approximately 13% of the annual energy demand in 1982.

The proposed development is located approximately 0.5km east of L'Anse au Clair, on Eastern Brook, with a catchment area of approximately 25 km^2.

The nearest river with streamflow records is the Saint Paul River in Quebec which is approximately 45 km west of Eastern Brook. This streamflow data was used to estimate the seasonal variation of Eastern Brook's streamflow as a function of its mean annual flow which was estimated as 70% of the mean annual total precipitation. The resulting flow data compared well with recorded streamflows for two other larger rivers further north with the main difference being an earlier thaw generated flow and a more even distribution of seasonal flows for Eastern Brook. Daily flow duration curves and flood frequency curves were then produced.

The basic scheme consists of:

(a) a 65m long intake dam of compacted till with an excavated, 30m wide spillway channel,

(b) a 1000m long penstock (800mm diameter),

(c) a 314 kW powerhouse,

(d) access roads to the powerhouse and intake dam,

(e) a 12.5 kV transmission line connecting the generator to the existing distribution system,

(f) a possible upstream storage reservoir.

The turbine selected was an Ossberger (cross-flow) type which provides a relatively flat efficiency curve from 20 to 100% power output and can operate adequately at an output of 10%. The selected turbine generator set would have an electrical full output of 314 kW. The turbine would be rated at a peak output of 443 HP (330.5 kW), with a net head of 66.4m and a plant discharge of $0.62m^3/s$ at full output.

An alternative smaller scheme, with an installed capacity of 192 kW, was also examined. The major civil works components would be unchanged except for the use of a smaller diameter (630mm) penstock.

The turbine selected for this smaller scheme is of the same type as the larger one. The turbine would be rated at a peak output of 271 HP (202 kW), with a net head of 65.22m and a plant discharge of $0.384m^3/s$.

Essentially, a reduced scheme was considered to avoid upgrading the existing single phase transmission line between L'Anse au Clair and Forteau, a distance of 10.5 km. This would reduce the capital investment required to implement the project. However, it is realized that an upgrading of the transmission line would be a benefit to the utility because the existing poles are in need of replacement.

The proposed hydro plant will operate in parallel with the existing diesel generating system. The project evaluation is based on the economics of replacing diesel generation from existing units only.

The geology of the area consists of formations of the Labrador Group of Lower Cambrian sediments. These contain shale, siltstone, limestones and sandstones. There is exposed bedrock at the proposed intake dam and storage dam sites. There is also exposed bedrock in numerous areas along the penstock route. Bedrock was not evident at the powerhouse site. Construction materials such as rock, sand, gravels, and till are available in and around the L'Anse au Clair area.

Technically, no abnormal engineering problems are anticipated with constructing this project. In order to complete the project by the fall of 1987, a start time of April, 1986, will be necessary. This will allow enough lead time on the manufacturing and delivery of the turbine and generator. The actual construction can be completed from May to October of 1987.

Based on real and projected 1985 prices, the capital cost for the basic 314 kW run-of-the-river scheme is $1 579 640. This includes $240 000 estimated for upgrading the present

single phase line from Forteau to L'Anse au Clair to 3 phase.

Capital cost for completing the reduced 192 kW scheme is $1 124 920 including the transmission lines to the town's single phase distribution system, estimated at $30 000.

An analysis was carried out to determine the benefits of constructing a storage dam upstream. Storage cost and benefit comparisons show that while a storage reservoir would result in useful benefits, the economics of adding the facility are very marginal. It did suggest, however, that if this project is developed further, storage options should be re-examined.

Other than the concerns expressed by Fisheries and Oceans concerning stream flows in Eastern Brook, the proposed development does not appear to pose any serious environmental problems. Except for the construction phase, the development will have no appreciable impact upon the community. The construction phase of the project will require 150 man-months of employment.

The projects were evaluated in terms of new hydro energy used to replace generation from diesel units, i.e., at the variable cost of diesel generation. No storage was considered. Based on these considerations, the basic evaluation of the hydro alternatives is based on direct comparison of hydro total and diesel variable generation costs, excluding escalation. This provided a direct measure of the mobility of the hydro projects as a function of interest rates.

The variable cost of diesel generation, i.e., excluding any capital related charges for equipment, is made up of fuel

costs, lubricating oil costs, and variable operation and maintenance costs. Based on these costs, it was assumed that the total variable diesel generation cost for L'Anse au Loup is 16.5 ¢/kWH.

The calculation of unit hydro electric generation costs is based on capital related charges of interest, depreciation, interim replacement, and insurance plus actual operation and maintenance costs, and general administration or overhead.

Based on a service life of 35 years, a comparison of these hydro generation costs with the variable or displacement values of diesel generation, which is 16.5 ¢/kWH, yields the corresponding breakeven interest rates of:

	BREAKEVEN INTEREST RATES	
	314 kW	192 kW
Hydro plant only	14.7%	13.3%
Hydro plus transmission	12.3%	12.9%
Hydro plus transmission costs increased by 10%	11.1%	11.7%

The above values show that if transmission line constuction costs are excluded, both the 314 kW and 192 kW schemes are quite attractive. With transmission costs added, both projects are still economically viable by accepted Canadian standards, based on the replacement of fuel criteria. The 314 kW project would displace more expensive diesel fuel, however, the reduced scheme feasibly is more attractive because of its low transmission capital costs.

Before commencing with this project, it is recommended that

further plan and profile surveys be undertaken, along with more extensive geotechnical investigations. Storage facilities should be reassessed as well as a reappraisal of the fisheries requirements.

ÉTUDE DE FAISABILITÉ D'UNE MINI-CENTRALE HYDRO-ÉLECTRIQUE À L'ANSE-AU-CLAIR (LABRADOR)

Résumé

Le conseil communautaire de l'Anse-au-Clair a chargé la Fenco Newfoundland Limited d'étudier la faisabilité technique et économique de l'aménagement d'une mini-centrale hydro-électrique dans la région. Cette étude a été financiée par Énergie, Mines et Ressources Canada, dans le cadre du Programme de démonstration dans les collectivités éloignées (PDCE), et par le conseil communautaire de l'Anse-au-Clair.

Cette petite collectivité située à l'extrémité sud de la côte du Labrador est l'une des onze (11) localités alimentées par une centrale au diesel d'une capacité disponible de 2 000 kW, située à l'Anse-au-Loup. Elle se classe au troisième rang au chapitre de la consommation d'énergie. En 1982, elle représentait environ 13 % de la demande annuelle.

Les installations proposées seraient aménagées à environ 0,5 km à l'est de l'Anse-au-Clair, sur le ruisseau Eastern, dont le bassin de réception est d'environ 25 km^2.

La rivière Saint-Paul (Québec), qui coule à environ 45 km à l'ouest du ruisseau Eastern, est la plus proche rivière sur le débit de laquelle on possède des données. Ces données ont servi à évaluer la variation saisonnière du débit du ruisseau Eastern en fonction de son débit annuel moyen qui a été évalué à 70 % de la précipitation annuelle moyenne totale. Les résultats obtenus correspondaient assez bien au débit établi pour deux autres rivières plus importantes situées plus au nord, le principal écart étant un débit provoqué plus tôt par le dégel et une répartition plus égale des débits saisonniers pour le ruisseau Eastern. On a ensuite établi des courbes des débits journaliers classés et de fréquence des crues.

Les ouvrages de base comprennent:

a) un barrage de 65 m de longueur fait de till compacté, et un déversoir en déblai de 30 m de largeur;

b) une conduite forcée de 1 000 m de longueur (800 mm de diamètre);

c) une centrale de 314 kW;

d) des routes d'accès à la centrale et au barrage;

e) une ligne électrique de 12,5 kV reliant la génératrice au réseau actuel de distribution; et

f) l'éventuel aménagement d'un réservoir de retenue en amont.

On a choisi une turbine Ossberger (en travers du courant) qui produit une courbe d'efficacité relativement peu accentuée, soit de 20 à 100 % du rendement, et qui peut bien fonctionner à une capacité de 10 %. Le groupe turbine-génératrice choisi aurait un rendement électrique total de 314 kW. La turbine aurait une puissance nominale de pointe de 443 HP (330,5 kW), à une hauteur de chute nette de 66,4 m et un débit de 0,62 m^3/s à plein régime.

On a également étudié un autre aménagement de moindre ampleur, ayant une capacité installée de 192 kW. Les ouvrages seraient les mêmes, sauf la conduite forcée dont le diamètre serait plus petit (630 mm).

La turbine choisie dans ce cas serait la même que pour l'aménagement de base. La turbine aurait une puissance nominale de pointe de 271 HP (202 kW), à une hauteur de chute nette de 65,22 m et un débit de 0,384 m^3/s.

La deuxième solution a été envisagée, avant tout, afin d'éviter d'avoir à remplacer la ligne électrique monophasée actuelle de 10,5 km reliant l'Anse-au-Clair et Forteau, ce qui permettrait de réduire les dépenses d'immobilisations à la mise en oeuvre du projet. Cependant, on reconnaît que le service public aurait avantage à remplacer la ligne étant donné que les poteaux ont besoin d'être changés.

La centrale hydro-électrique proposée et la centrale actuelle au diesel seraient exploitées simultanément même si l'évaluation comme telle du projet repose sur les incidences économiques liées uniquement au remplacement des groupes existants à moteur diesel.

La géologie régionale comprend des formations du groupe de Labrador, composées de sédiments du Cambrien inférieur. Ceux-ci renferment du schiste, du limon, de la pierre calcaire et du grès. On retrouve de la roche en place exposée à l'emplacement proposé du barrage et du réservoir de retenue. On en retrouve également à divers endroits le long du traçé de la conduite forcée. Cependant, l'emplacement de la centrale ne semble pas en comporter. On pourrait se procurer des matériaux de construction tels que la roche, le sable, le gravier et le till dans la région de L'Anse-au-Clair.

On ne prévoit aucun problème technique inhabituel au cours de l'étape de construction. Pour achever le projet à l'automne 1987, il faudrait que les travaux soient entrepris en avril 1986, ce qui laisserait suffisamment de temps pour fabriquer et pour livrer la turbine et la génératrice. Les travaux de construction proprement dits pourraient être exécutés de mai à octobre 1987.

D'après les coûts réels et prévus de 1985, les immobilisations nécessaires pour réaliser la centrale de base de 314 kW au fil de l'eau s'élèvent à 1 579 640 $. Cette somme comprend les 240 000 $ prévus pour convertir la ligne actuelle entre Forteau et L'Anse-au-Clair en ligne triphasée.

Le coût d'aménagement de la centrale plus petite de 192 kW s'élève à 1 124 920 $, dont 30 000 $ à peu près serviraient à l'installation de lignes de transport jusqu'au réseau de distribution monophasé de la localité.

On a effectué une analyse pour déterminer les avantages reliés à l'aménagement d'un réservoir de retenue en amont. Il ressort de l'analyse des coûts et des avantages relatifs que, si l'aménagement d'un réservoir de retenue apporterait des avantages appréciables à la collectivité, cette installation ne se justifie que très difficilement sur le plan économique. Cependant, si ce projet va plus loin, il faudrait alors réexaminer cette possibilité.

Mises à part les préoccupations formulées par Pêches et Océans au sujet des débits du ruisseau Eastern, l'aménagement proposé ne semble pas menacer l'environnement. Sauf pendant les travaux de construction, le projet n'aura aucune répercussion appréciable sur la collectivité. Il faudra affecter 150 mois-hommes à la construction du projet.

Les projets ont été évalués en fonction de la nouvelle énergie hydro-électrique nécessaire pour remplacer la production d'énergie au diesel, c'est-à-dire selon un coût variable de l'énergie produite grâce au diesel, et sans tenir compte de l'aménagement possible d'un réservoir. Ainsi, l'évaluation fondamentale des deux solutions possibles repose sur la comparaison directe du coût total de production d'énergie hydro-électrique et du coût variable de production d'énergie grâce au diesel, sans tenir compte d'un facteur d'indexation quelconque. Cette méthode a permis d'obtenir une mesure directe de la mobilité des centrales en fonction des taux d'intérêt.

Le coût variable de production d'énergie au moyen de moteurs diesel, duquel est exclu tout coût d'acquisition de l'équipement, représente le coût du combustible, des huiles lubrifiantes et les coûts variables d'exploitation et d'entretien. D'après ces coûts, on a évalué à 16,5 ¢/kWh le coût variable total de production d'énergie au moyen de moteurs diesel pour L'Anse-au-Loup.

Le calcul des coûts unitaires de production d'énergie électrique repose sur le paiement d'intérêts liés au capital, la dépréciation, le remplacement provisoire, l'assurance ainsi que les coûts réels d'exploitation et d'entretien et les frais administratifs ou les frais généraux.

Si l'on fixe à 35 ans la durée d'utilisation des installations, la comparaison entre le coût de production d'énergie hydro-électrique et la valeur variable ou de remplacement de la production d'énergie au diesel, laquelle s'élève à 16,5 ¢/kWh, permet d'obtenir les taux d'intérêt correspondants permettant d'atteindre le seuil de rentabilité:

Taux d'intérêt permettant d'atteindre

	314 kW	192 kW
Centrale seulement	14,7%	13,3%
Centrale et transmission	12,3%	12,9%
Centrale et augmentation de 10% du coût de transmission	11,1%	11,7%

Comme on peut le constater ci-haut, les deux options, soit la centrale de 314 kW et celle de 192 kW, sont assez intéressantes si les coûts liés à la pose de la ligne de transport sont exclus. Et même si on y ajoute ces derniers coûts, les deux projets sont encore économiquement viables selon les normes canadiennes reconnues, étant donné qu'ils servent à remplacer du combustible. La centrale de 314 kW permettrait de remplacer un combustible diesel plus coûteux; cependant, la centrale de moindre capacité est plus intéressante étant donné les faibles coûts de transport d'énergie qu'elle suppose.

Avant de lancer ce projet, il est recommandé que d'autres plans et études de terrain, ainsi que des études géotechniques plus poussées, soient entrepris. Il conviendrait de réévaluer l'aménagement possible d'un réservoir de retenue et les besoins liés à la pêche.

1.0 INTRODUCTION

1.1 Study Background

Fenco Newfoundland Limited was contracted by the L'Anse au Clair Community Council to investigate the technical and economic feasibility of a mini-hydro development in that area. The study was carried out under the Remote Community Demonstration Program (RCDP) of the Federal Government.

The feasibility study was conducted from July to October, 1984, when the draft final report was submitted.

Following review of the draft report, two additional requirements were introduced:

- The sizing of the project and the calculation of energy benefits must assume that at least 25% of the natural run-off is left in the Eastern Brook stream to meet fisheries requirements.

- An alternative smaller scheme should be considered. This reduced development would be sized to meet the requirements of L'Anse au Clair itself and would avoid the requirement for establishing three phase transmission between the power plant and the L'Anse au Loup system at Forteau.

As a result of these modifications, the final study report was issued in February, 1985.

The study was sub-divided into five major tasks:

Task 1 - Preliminary Site Investigation and Data Collection.

Task 2 - Field Survey and Development of Alternatives.

Task 3 - Preliminary Design and Cost Benefit Analysis.

Task 4 - Final Design Selection and Economic Analysis.

Task 5 - Final Report Production.

1.2 Program Background

The Remote Community Demonstration Program (RCDP) supporting this study is a program managed by the Department of Energy, Mines and Resources Canada. The objective of this program is to help remote communities and agencies responsible for their energy supply to identify more appropriate energy alternatives and energy conservation opportunities. The program is divided into two phases. Phase 1 offers limited financial assistance for carrying out studies to explore these alternatives and opportunities. Phase 2 will contribute funds to a limited number of demonstration projects in selected remote communities across Canada. The program will then transfer the knowledge gained from funded studies and projects to all communities and agencies where this knowledge is needed.

1.3 Authorization

Fenco Newfoundland Limited submitted a study proposal on behalf of the L'Anse au Clair Town Council on September 12, 1983. In June of 1984 final financing arrangements were negotiated with Energy, Mines and Resources Canada. Energy, Mines and Resources is contributing 91.25% of the

cost with the Community of L'Anse au Clair paying the remainder. Fenco Newfoundland Limited was then authorized to begin the feasibility study.

1.4 Terms of Reference

The Terms of Reference for the study were as stated in the Work Statement in Annex A to the agreement between Canada and the Community Council of L'Anse au Clair dated August 10, 1984 (see Appendix 1).

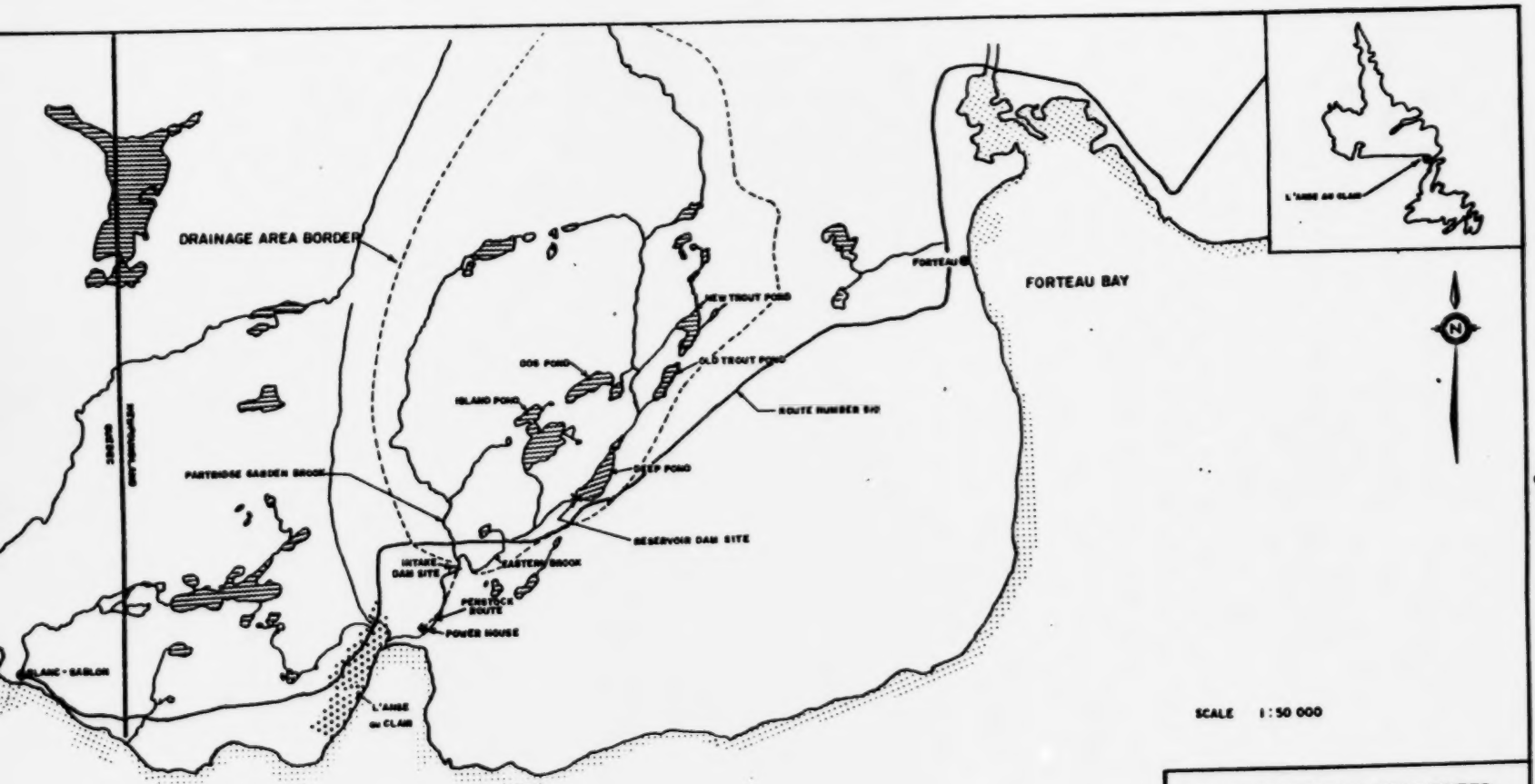
2.0 GENERAL PROJECT DESCRIPTION

2.1 Regional Setting

L'Anse au Clair is a small settlement on the extreme south coast of Labrador, on the Strait of Belle Isle (Figure 2.1). The community has a population of 267 people (1981 Census of Canada) and provides seasonal economic activity in the fishing, agriculture and tourism industries.

The coastal terrain in this south coast region extends north-eastward from the Quebec-Newfoundland border and is characterized by rapidly rising ground extending up to levels of from 180 to 300 metres above sea level within a few kilometres from the coast. Water draining from the higher terrain in several cases is discharged through relatively prominent valleys extending in from the coast. The combination of the relatively high watershed areas and the substantial drop of the discharge over a reasonably short distance in the valleys suggests that suitable mini-hydro sites should be available within the area.

L'Anse au Clair along with eleven other settlements are supplied with electrical energy by a 2000 kw firm capacity diesel generating station located at L'Anse au Loup. L'Anse au Clair is the third largest user of electricity of the eleven communities making up approximately 13% of the annual energy demand in 1982. L'Anse au Loup and Forteau are the biggest energy users at 25 and 19 percent respectively in 1982 (Ref. 1). Appendix 1 contains a general description of the L'Anse au Loup Distribution System and Community Profiles on L'Anse au Clair and L'Anse au Loup.



FENCO NEWFOUNDLAND LIMITED

LOCATION MAP

FIGURE 2.1

Access to L'Anse au Clair is by road, sea, and air. Labrador Airways has a scheduled service to Blanc Sablon, Quebec, only 5 km west of L'Anse au Clair. There is also a regular daily ferry service connecting this south coast portion of Labrador to the Island portion of Newfoundland. The ferry crossing is from St. Barbes on the Island's west coast to Blanc Sablon on the Quebec-Labrador border. The south coast Labrador Highway runs from Blanc Sablon northeast to Red Bay linking the eleven small Newfoundland communities.

2.2 Proposed Development

In the immediate area northeast of L'Anse au Clair there is a catchment area of about 25 km^2 which drains into Eastern Brook approximately 0.5 km from the town. The river goes through a substantial drop of approximately 80 m in its last 1500 m run to the coast. It is on this area that this mini-hydro study concentrates.

The proposed mini-hydro development is located approximately 0.5 km east of L'Anse au Clair (Figure 2.2). For the basic scheme, the major civil structures will consist of:

(a) a 65 m long intake dam of compacted till, an adjacent excavated, 30 m wide spillway channel,
(b) a 1000 m long penstock (800 mm diameter),
(c) a 314 kw powerhouse,
(d) access roads to the power house and intake dam,
(e) a 12.5 kV transmission line connecting the generator to the existing distribution system,
(f) a possible upstream storage reservoir.

An alternative smaller scheme with an installed capacity of 192 kw was also examined. The major civil works components would be unchanged except for the use of a smaller diameter (630mm) penstock.

It is proposed that the hydro plant operate in parallel with the existing generation system. The electricity being generated by the mini-hydro plant will reduce generation from the existing diesel generating facility.

Secondary benefits will result from increased reliability of the overall system, improved distribution performance over the L'Anse au Clair/Forteau system and a possible deferment of additional diesel generation.

The project evaluation is based on the economics of replacing diesel generation from existing units only.

3.0 SITE INFORMATION

3.1 Location

The proposed development is just east of the community of L'Anse au Clair as shown in Figure 2.1. Access to the powerhouse will be by road from the town while the intake and reservoir dams will be accessible from highway 510 running northeast from the community.

3.2 Regional Geology

The area around L'Anse au Clair is comprised of two formations of the Labrador Group of Lower Cambrian sediments, namely the Forteau and Bradore formations. The Forteau Formation contains shale, calcareous siltstone, minor limestone, oolitic limestone, and quartz sandstone. The Bradore Formation contains red to buff arkosic sandstone along with minor conglomerate and hematitic sandstone. The repeated glaciation in the area has resulted in overburden being thin or non-existent on the rocky plateau areas and sand deposits being present in low valley areas. Such is the case near the mouth of Eastern Brook where there is a large sand deposit on the west bank stretching along the sea shore.

3.3 Foundation Conditions

Intake Dam

At the intake dam site there is exposed bedrock on the east bank and in the stream bed the rock lies in a smooth, almost horizontal plane. This will simplify foundation preparation. The rock face on the east side and the natural embankment on the west side will act as two natural

abutments for the dam. There should be a minimum amount of grubbing and excavation required.

Reservoir Dam

A possible upstream reservoir dam site is located in a natural ravine approximately 150 m downstream of Deep Pond.

Bedrock is exposed on both sides of the stream bed. At a point 40 m from the stream the northwest bank rises at a 1:2 slope. The slope is covered with low shrub and wild grass. For the first 40-50 m, it appears that bedrock is relatively close to the surface. The southeast embankment rises at a 1:4 slope and is covered with low shrub. From the outcrops in the area it appears that for the first 40-50 m from the stream bedrock is relatively close to the surface. The construction of a reservoir dam in this area should not be a problem with regards to foundations and a minimum amount of site preparation should be required.

Powerhouse

The proposed powerhouse site is located near the sea shore and immediately adjacent to the stream on the west bank. (Figure 5.1). There are no bedrock outcrops visible in the immediate area. The west bank of the stream consists of an exposed sand bank 2 m high, intermixed with small boulders. There is a large deposit of sand to the area west of the stream which is an extension of the river bank. The stream bed is made up of cobbles, rocks and boulders which is typical for the lower stretch of the stream. It was impossible to determine visually if the stream had eroded to bedrock because of this matrix of cobbles and boulders. In any event the stream appears to have reached its limit of erosion in this area. For the purposes of this study,

the estimated cost for the powerhouse construction has been based on a concrete slab footing rather than a bedrock foundation. Should the project be approved, then further investigation regarding foundation conditions should be carried out before proceeding to design powerhouse foundations.

3.4 Construction Materials

The construction materials which are readily available include fine sand, gravel, rock, and small thin deposits of till.

An existing borrow area at the north end of the town near the pumphouse access road is used as a supply for fine sands by the town and other users. Till from deposits in that area was used to construct the existing water supply dam. This area will be one of the possible sources of till for the intake/storage dam. In addition, numerous small deposits of glacial origin have been identified by the Mineral Development Division of the Department of Mines and Energy. In all probability, many of these deposits will have a silt content suitable for impervious fill. While non-overflow compacted till sections have been used, an alternative rockfill timber crib to replace this section would cost about the same.

There are several possible sources of road gravel in the area. For the construction of the access roads to the powerhouse, intake dam and penstock, a deposit is located near Route 510 at a point 400 m from the intake dam. Another source of gravel and rock is located approximately 500 m northeast of the storage dam near Route 510. This is an existing quarry and borrow area which was used to construct Route 510. This will be a suitable source for constructing the access road and reservoir dam.

3.5 Mapping

For overall coverage of the area, the only maps available were those produced by the Survey and Mapping Branch, Department of Energy, Mines and Resources. They have a scale of 1:50 000 with a 50 feet contour interval. To improve the assessment of proposed dam sites and penstock routes additional smaller scale mapping was necessary.

Additional mapping of the river valley from Highway 510 to L'Anse au Clair Harbour was thus produced from existing aerial photographs. This map was produced at a scale of 1:2500 with 2 m contours. Similar mapping is available from the Department of Municipal Affairs covering the Town of L'Anse au Clair only.

4.0 HYDROLOGY

4.1 The Catchment Area

The catchment or drainage area, at the intake/division wier, determined by planimetry from 1:50 000 scale maps is 25 km^2. Fifty- five percent (55%) of this area drains into Eastern Brook above the proposed upstream storage reservoir location.

Total catchment area = 25.0 km^2
Portion of catchment area upstream of reservoir dam = 13.8 km^2 (55%)

4.2 Available Hydrometric Information

Direct measurement of precipitation or streamflow is not available for the Eastern Brook catchment. Therefore indirect methods had to be used for estimates of hydrologic parameters using data from neighbouring areas.

Data Investigated:

Canadian Climate Normals

(i)	Precipitation Data Blanc Sablon	1951-1980
(ii)	Precipitation Data Cartwright	1951-1980
(iii)	Precipitation Data Goose Bay	1951-1980

Hydrological Atlas of Canada,
and Climat du Québec Septentrinal

(iv)	Precipitation Isohyet Figures - Canada	1931-1960
		1941-1970
(v)	Water Losses Isohyet Figures - Canada	1931-1960

Streamflow records

(vi)	Streamflow Data, St. Paul's River, Quebec	1967-1981
(vii)	Streamflow Data, Eagle River, Labrador	1966-1982
(viii)	Streamflow Data, Alexis River, Labrador	1978-1982

Monthly Precipitation Records

(ix)	Blanc Sablon	1966-1980
(x)	Cartwright	1966-1980
(xi)	Goose Bay	1966-1980

These records are included in Appendix 3.

The precipation data available for Blanc Sablon (1951-1980) about 9 km west of the L'Anse au Clair catchment centre was used to estimate the mean yearly precipitation for the study area.

The nearest river with stream flow records is the Saint Paul River at the Quebec Station 76601. Monthly and annual mean flows were available from 1967-1981. Daily flow data was obtained for 1967 to 1975.

The Saint Paul streamflow data was used to estimate the distribution of flows for Eastern Brook as a function of the mean annual streamflow. The mean annual streamflow for Eastern Brook was estimated as 70% of the mean annual total precipitation (see Section 4.4).

4.3 Climate

The Eastern Brook catchment is greatly affected by the prevailing Gulf of St. Lawrence weather conditions making

this southerly zone the highest precipitation area in Labrador (Ref. 7, 8). Of this precipitation about 40% falls as snow. The variability of the annual precipitation is approximately 20% as expressed by the coefficient of variation.

Mean yearly temperature is about 1°C with monthly means ranging from -12°C in January to 13°C in July. Average values for daily extremes vary from -15°C (January) to 16°C (July). Absolute minima and maxima on record are respectively -37°C and 27°C. This south coast region has the highest mean January temperature in the Labrador region. The warmer winters cause earlier spring thaws and a more even distribution of monthly runoff.

Because of the chilling effects of the Labrador oceanic current, the latest spring frost can occur well into the month of June (with a 50% probability) while the first autumn frost will occur somewhere towards the end of September (50% probability), the median value for the frost-free season being 120 days.

4.4 Runoff Estimates

General runoff coefficients were estimated for the Saint Paul catchment and the Eagle River catchment to get an appreciation of the areas' runoff characteristics. General isohyets of precipitation and runoff for this region were also examined. General geological features of the region were examined for comparison purposes. A conservative estimate of a runoff coefficient for the Eastern Brook catchment is 70%.

Using complete streamflow data sets for the Saint Paul catchment for three years (1977, 1978, 1980) where there

is complete precipitation data available for Blanc Sablon, an 88% runoff coefficient was calculated. In 1968, 1969, and 1976 there are complete precipitation data for Blanc Sablon but some of the measurements are noted as estimated. If these three years of data are added to the above analysis a 77% runoff coefficient is calculated. All other records for streamflow at Saint Paul and precipitation at Blanc Sablon have periods of no measurements in one or the other.

An examination of two isohyets of total annual precipitation for Eastern Canada (1931-1960, 1941-1971) shows an approximate 5% increase in precipitation for the centre of the Saint Paul catchment over Blanc Sablon. This would therefore decrease slightly the runoff coefficients noted in the previous paragraph to approximately 84% and 73%.

For the Eagle River catchment annual precipitation means for Goose Bay and Cartwright were averaged to represent its total precipitation. These two meteorological stations are situated on both sides of the catchment area. For the same ten years streamflow records for the Eagle River were compared. The result was a 76% runoff coefficient for the Eagle River catchment.

Isohyets of runoff losses (1931-1960) for Canada were also compared to isohyets of total precipitation for the same period. A runoff coefficient of 72% for the L'Anse au Clair area was approximated from this comparison. There has not been a great amount of hydrometric and meteorological data collected for Labrador and for this part of Quebec. Most of the stations that do exist are along the coastal areas. These isohyet charts should therefore be treated as general indications of precipitation and runoff patterns only.

With the above information in mind a conservative value for the runoff coefficient for the Eastern Brook catchment is assumed to be 70%. This runoff coefficient was applied to the annual mean precipitation for Blanc Sablon for 30 years (1951-1980) and used in deriving daily flows for Eastern Brook based on recorded flows for the Saint Paul River.

Discussions with local fisheries personnel and local residents ensured us that Eastern Brook flows all year round with no complete freeze-up.

Daily Flow Duration Curve and Mean Annual Streamflow

Studies carried out in the Maritimes (Ref. 9) and elsewhere (Ref. 10) have shown that for hydrologically similar basins a common, non-dimensional daily flow duration curve can be derived. The curve is independent of drainage area. The normalization is accomplished by dividing the daily flow values by the long term mean yearly flow. Such a curve, derived for a gauged basin can be applied directly to an ungauged basin for which an estimate of the mean yearly flow is available.

Seventy percent (70%) of the long term annual mean precipitation of 1160 mm for Blanc Sablon gives an annual mean runoff of 812 mm for the Eastern Brook catchment. This equates to a mean annual streamflow of 0.64 m^3/s for this 25 km^2 catchment.

A dimensionless daily flow duration curve was therefore derived for the Saint Paul River at Station 76601 and used for the Eastern Brook catchment at the intake.

Table 4.1 - Daily Flow Duration Data, for Saint Paul's River.

TABLE 4.1 SAINT PAUL RIVER - DAILY FLOW DURATION DATA

%	VALUE (m^3/sec)	Q CAP.FAC (m^3/sec)	CAP.FAC.
0.00	43000	5138.65	0.117
2.00	26900	5025.99	0.187
4.00	21800	4855.99	0.223
6.00	16800	4622.65	0.275
8.00	13000	4343.99	0.334
10.00	11100	4179.32	0.377
12.00	10000	4054.65	0.405
14.00	9100	3940.65	0.433
16.00	8200	3802.65	0.464
18.00	7430	3674.32	0.495
20.00	6790	3550.59	0.523
22.00	6350	3459.65	0.545
24.00	5970	3370.99	0.565
26.00	5570	3272.32	0.587
28.00	5300	3196.52	0.603
30.00	5000	3112.52	0.623
32.00	4680	3012.25	0.644
34.00	4470	2943.65	0.659
36.00	4220	2853.32	0.677
38.00	4010	2778.32	0.693
40.00	3830	2707.52	0.707
42.00	3670	2642.45	0.720
44.00	3550	2590.45	0.730
46.00	3380	2514.52	0.744
48.00	3200	2429.32	0.759
50.00	3070	2366.05	0.771
52.00	2940	2299.32	0.782
54.00	2800	2225.59	0.795
56.00	2690	2164.72	0.805
58.00	2590	2108.05	0.814
60.00	2500	2054.65	0.822
62.00	2410	2000.05	0.830
64.00	2300	1930.39	0.839
66.00	2210	1872.19	0.847
68.00	2120	1811.59	0.855
70.00	1990	1722.32	0.865
72.00	1890	1650.99	0.874
74.00	1780	1571.05	0.883
76.00	1670	1488.19	0.891
78.00	1610	1442.19	0.896
80.00	1410	1283.52	0.910
82.00	1200	1114.12	0.928
84.00	1050	989.12	0.942
86.00	890	853.65	0.959
88.00	835	805.62	0.965
90.00	700	605.92	0.980
92.00	645	635.69	0.986
94.00	572	568.04	0.993
96.00	515	513.70	0.997
98.00	485	484.70	0.999
100.00	440	440.00	1.000

Table 4.2 - Daily Flow Duration Data, Derived for Eastern Brook.

Figure 4.1 - Daily Flow Duration Curve - Eastern Brook.

Figure 4.2 - Daily Flow Duration Curve - Eastern Brook, 0-2 m^3/s range.

Other Streamflow Estimates

A drainage area proration of Eagle River streamflow data (1967-1981) gives a mean annual flow estimate of 0.62 m^3/s for the Eastern Brook catchment. A drainage area proration of Saint Paul's River streamflow data (1967-198) gives a mean annual flow estimate of 0.59 m^3/s for the Eastern Brook catchment.

A smaller amount of streamflow data is available for the Alexis River which has a drainage area of 2310 km^2. Although data is only available from 1978, a drainage area proration of this data helps confirm the negligible effect of drainage area size. The result of the Alexis River proration for Eastern Brook gives an annual mean flow of 0.60 m^3/s.

The derived mean annual flow of 0.64 m^3/s for the Eastern Brook catchment with its higher precipitation records at Blanc Sablon is therefore considered to be reasonable.

Monthly Distribution of Streamflow

The best information on distribution of flows for the Eastern Brook catchment is obtained from the Saint Paul River because of its closer proximity to Eastern Brook on Labrador's south coast. The coastal climatic conditions and prevailing southwest winds would have a more similar effect on the Saint Paul catchment as compared to the Eagle River catchment further north.

TABLE 4.2 EASTERN BROOK - DAILY FLOW DURATION DATA

%	VALUE (m^3/sec)	Q CAP.FAC (m^3/sec)	CAP.FAC.
0.0	5.49	0.64	0.117
2.00	3.37	0.63	0.187
4.00	2.73	0.61	0.223
6.00	2.10	0.58	0.275
8.00	1.63	0.54	0.334
10.00	1.39	0.52	0.377
12.00	1.25	0.51	0.405
14.00	1.14	0.48	0.433
16.00	1.03	0.48	0.464
18.00	0.93	0.46	0.495
20.00	0.85	0.44	0.523
22.00	0.80	0.43	0.545
24.00	0.75	0.42	0.565
26.00	0.70	0.41	0.587
28.00	0.66	0.40	0.603
30.00	0.63	0.39	0.623
32.00	0.59	0.38	0.644
34.00	0.56	0.37	0.659
36.00	0.53	0.36	0.677
38.00	0.50	0.35	0.693
40.00	0.48	0.34	0.707
42.00	0.46	0.33	0.720
44.00	0.44	0.32	0.730
46.00	0.42	0.31	0.744
48.00	0.40	0.30	0.759
50.00	0.38	0.30	0.771
52.00	0.37	0.29	0.782
54.00	0.35	0.28	0.795
56.00	0.34	0.27	0.805
58.00	0.32	0.26	0.814
60.00	0.31	0.26	0.822
62.00	0.30	0.25	0.830
64.00	0.29	0.24	0.839
66.00	0.28	0.23	0.847
68.00	0.27	0.23	0.855
70.00	0.25	0.22	0.865
72.00	0.24	0.21	0.874
74.00	0.22	0.20	0.883
76.00	0.21	0.19	0.891
78.00	0.20	0.18	0.896
80.00	0.18	0.16	0.910
82.00	0.15	0.14	0.928
84.00	0.13	0.12	0.942
86.00	0.11	0.11	0.959
88.00	0.10	0.10	0.965
90.00	0.09	0.09	0.900
92.00	0.06	0.08	0.986
94.00	0.07	0.07	0.993
96.00	0.06	0.06	0.997
98.00	0.06	0.06	0.999
100.00	0.06	0.06	1.000

Figure 4.1

&

Figure 4.2

The monthly mean discharges for Saint Paul River were converted to Eastern Brook discharges using the ratio of their mean annual flows. The following distribution results:

Eastern Brook Mean Monthly Discharges (m^3/s)

J	F	M	A	M	J	J	A	S	O	N	D	Mean
.21	.19	.18	.22	2.04	1.61	.60	.55	.59	.66	.51	.34	.64

It can be seen from Tables 4.3 and 4.4 that the streamflows at Eagle River are more concentrated in May and June, and peak in June. The streamflows for Saint Paul River further south shows relatively higher flows in the winter months with peak flows in May. In actual fact because Eastern Brook is further south again and more affected by the coastal climatic conditions in the Gulf of St. Lawrence, its flows should peak even earlier.

Due to its relatively milder climate the flows should be more evenly distributed with less extreme low flows during winter months. Discussions with fishery people in L'Anse au Loup and local people in L'Anse au Clair have demonstrated that the river does indeed flow all winter long with no complete freeze ups. Mean January daily temperatures on the average at L'Anse au Clair are about 5°C and 7°C warmer than in the Saint Paul and Eagle River catchments respectively (Ref. 7).

Table 4.3 Saint Paul River - Monthly and Annual Mean Discharges - m^3/s

Annual	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Mean
1967	-	-	-	-	-	-	-	161	177	-	-	-	-
1968	40.7	45.1	26.3	50.4	386	266	162	212	191	182	123	74.2	147
1969	56.6	106	77.7	55.1	470	564	162	140	87.6	97.0	137	227	182
1970	102	72.6	44.6	51.0	319	277	221	101	73.4	207	113	81.9	139
1971	53.6	35.4	25.4	70.5	600	210	115	112	213	90.1	132	67.4	145
1972	-	-	-	-	-	-	-	-	-	178	-	-	-
1973	21.4	14.9	13.9	14.4	633	380	217	124	81.5	101	77.5	77.4	148
1974	45.9	21.6	17.0	18.8	218	536	136	75.3	64.0	120	87.7	77.4	118
1975	29.0	14.3	13.8	16.4	437	300	69.5	95.3	224	122	169	82.0	131
1976	40.0	37.8	24.4	68.6	494	124	64.6	171	233	148	108	70.4	132
1977	73.8	41.5	29.8	42.2	533	693	90.0	107	182	240	179	85.5	192
1978	52.0	28.6	23.2	23.1	678	685	143	101	115	250	81.2	40.7	186
1979	47.7	65.3	181	195	580	116	104	182	176	150	71.9	45.6	160
1980	42.8	30.6	25.2	45.2	592	518	264	157	113	183	211	66.2	188
1981	48.0	95.3	79.9	-	-	-	147	117	90.3	-	-	-	-
Mean	50.3	46.8	44.8	54.2	495	389	146	133	144	159	124	83.0	156

DRAINAGE AREA = 6630 km^2

Table 4.4 Eagle River - Monthly and Annual Mean Discharges - m^3/s

Annual	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Mean
1966	-	-	-	-	-	-	-	-	-	435.0	255.0	105.0	-
1967	66.4	49.3	39.7	35.7	106.0	538.0	274.0	452.0	228.0	-	-	-	-
1968	-	-	-	-	-	-	-	-	-	348.0	266.0	125.0	-
1969	98.9	86.2	78.7	74.6	494.0	1180.0	360.0	207.0	133.0	232.0	226.0	144.0	276.2
1970	87.5	63.7	52.2	48.6	702.0	648.0	327.0	300.0	134.0	175.0	124.0	74.0	228.0
1971	53.6	43.2	37.2	197.0	1400.0	909.0	263.0	187.0	283.0	288.0	135.0	83.0	323.3
1972	45.4	31.2	24.1	20.7	273.0	1310.0	224.0	242.0	294.0	261.0	101.0	50.9	239.8
1973	36.9	29.8	26.5	32.8	1140.0	585.0	270.0	148.0	94.2	100.0	107.0	61.7	219.3
1974	43.0	34.4	29.6	29.0	454.0	1470.0	375.0	213.0	109.0	220.0	95.2	36.3	259.0
1975	22.4	17.2	14.3	12.4	276.0	813.0	263.0	201.0	291.0	170.0	117.0	62.8	188.3
1976	46.3	37.7	32.6	162.0	927.0	396.0	119.0	264.0	521.0	336.0	176.0	120.0	261.5
1977	63.2	44.3	37.3	64.4	739.0	1570.0	449.0	425.0	189.0	210.0	102.0	75.0	330.7
1978	54.7	43.8	35.9	47.2	517.0	1550.0	386.0	169.0	242.0	515.0	175.0	92.9	319.0
1989	68.1	69.1	69.0	-	-	337.0	288.0	333.0	292.0	290.0	194.0	67.0	-
1980	44.1	34.4	29.3	-	-	1010.0	533.0	339.0	187.0	333.0	352.0	143.0	-
1981	89.0	68.0	57.1	76.8	1260.8	1090.0	400.0	271.0	158.0	398.0	255.0	91.1	351.2
1982	57.7	43.8	35.7	34.7	324.0	1390.0	502.0	203.0	258.0	129.0	155.0	108.0	270.1
Mean	58.5	46.4	39.9	64.3	662.5	986.4	335.5	263.6	227.5	277.5	177.2	90.0	269.1

DRAINAGE AREA = 10 900 km^2

4.5 Flood Studies

Studies carried out in Quebec have shown that for region 07, which includes Eastern Brook, the most appropriate theoretical fit for yearly floods is provided by the Log Person III distribution (Ref. 11) which was therefore adopted in this study.

Flood estimates for Eastern Brook were obtained in two steps. First floods of different return periods were derived for the Saint Paul River using the Log Person III fit on available data. The flood estimates thus obtained were then prorated to produce corresponding values for Eastern Brook.

Since the proposed power plant at L'Anse au Clair will be operated as run-of-river i.e., without storage operation to reduce flow peaks, the flood parameter of interest to this project is the maximum instantaneous flow (MIF). On the Saint Paul River the MIF is available for seven years while the maximum daily flow (MDF) is available for another five years. The mean value of the ratio of MIF to MDF is 1.05 for the seven years of available MIF. This ratio was used to estimate the MIF's for the five years when only MDF was observed. Thus, a total of 13 years of MIF became available (see Table 4.5).

A Log Pearson III fit was applied to the Saint Paul floods and transferred to Eastern Brook using the Creager equation which relates flood mangitude to drainage area according to the formula:

$$g = C\ (0.386\ A)\ \{0.936A^{-0.048} - 1\}$$

where g = specific flow in m^3/s per sq km

A = drainage area in sq km

C is a coefficient which depends on the return period.

Table 4.6 gives the results obtained for different return periods, the distribution being shown graphically in Figures 4.3 and 4.4.

For the purpose of the layouts and costs developed in this study, the spillway design flow is that with a 1000 year return period. However, it should be noted that this is only marginally higher than the two year return period flow.

TABLE 4.5

Saint Paul River at Station 76601
Maximum Flows observed in Years 1967-1979

Year	Maximum Daily Flow (m^3/s)	Maximum Instantaneous Flow (m^3/s)	MIF/MDF
1967	943	990	1.025
1968	521	547*	
1969	1010	1060*	
1970	807	875	1.084
1971	1240	1290	1.040
1972	697	732*	
1973	1100	1150*	
1974	1050	1100*	
1975	906	950*	
1976	1060	1160*	1.094
1977	1520	1570	1.032
1978	2440	2560	1.049
1979	1130	1140	1.009

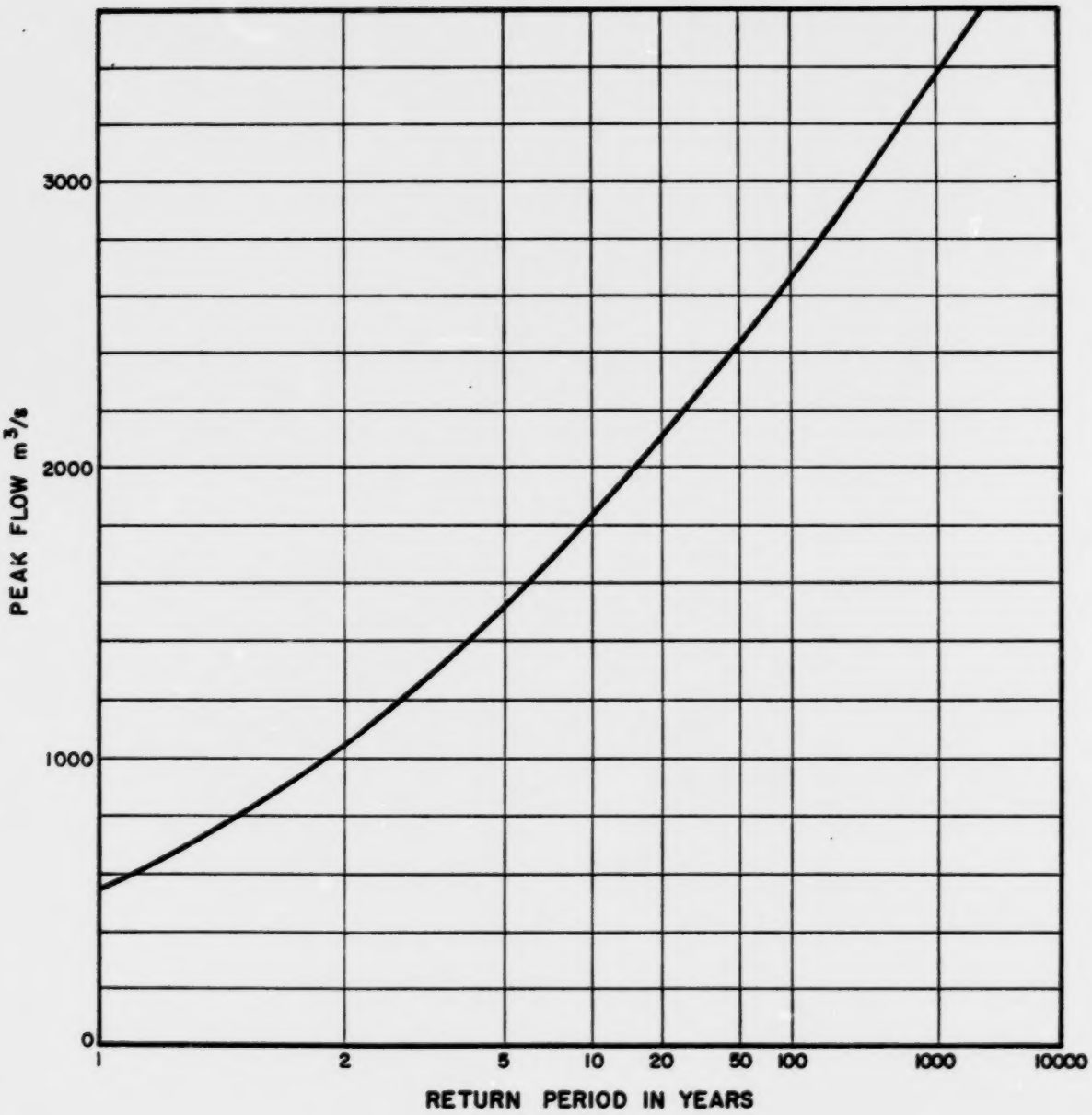
*MIF = MDF x 1.05

TABLE 4.6

Flood Frequencies Estimated by Log Pearson III Fit

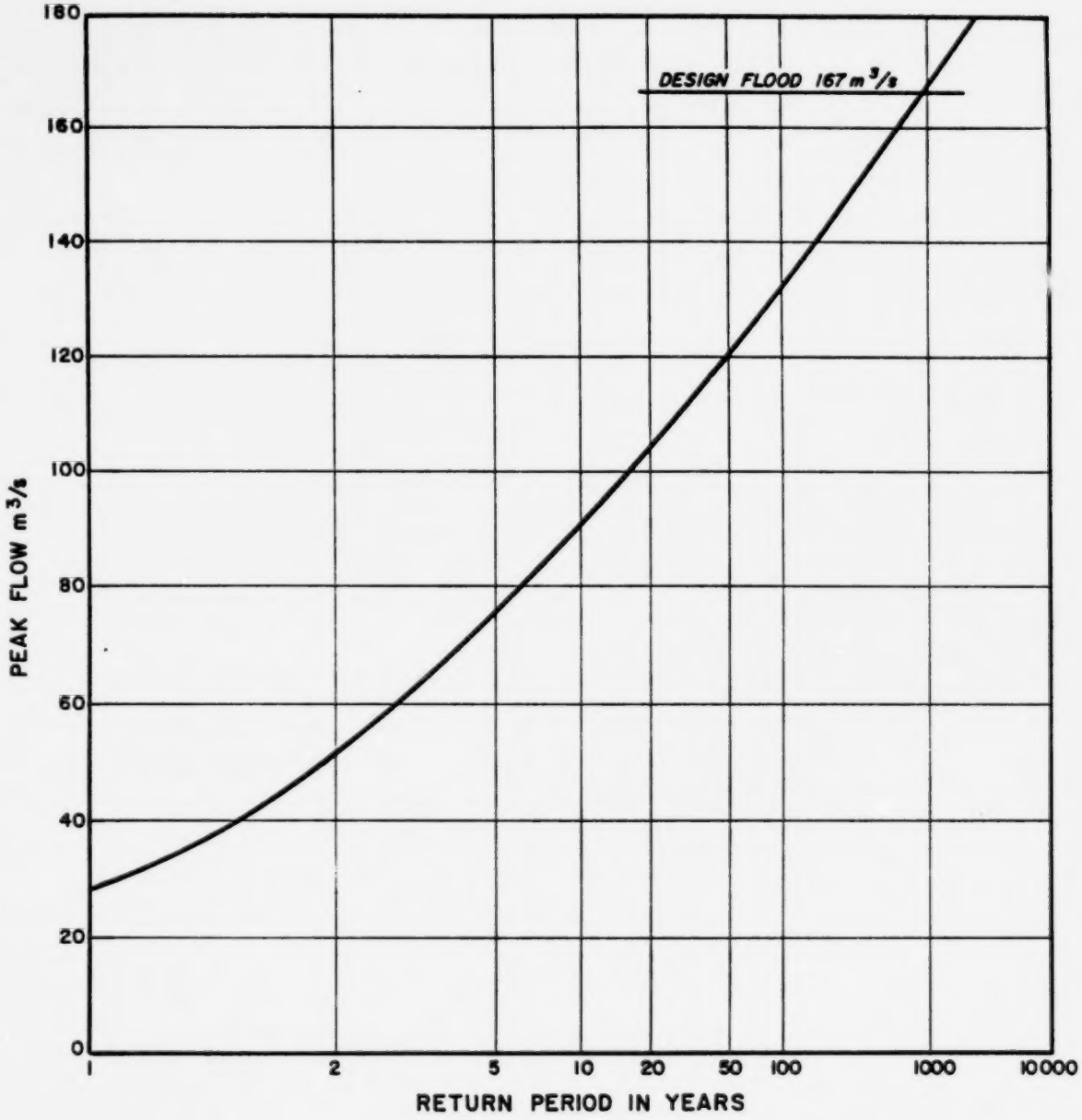
Return Period (year)	Flood Flow (m^3/s)	
	St. Paul	Eastern Brook
2	1040	52
10	1820	91
20	2090	104
50	2420	121
100	2650	132
500	3150	157
1000	3350	167
2000	3970	198

FIGURE 4.3



SAINT PAUL RIVER
FLOOD FREQUENCY CURVE

FIGURE 4.4



EASTERN BROOK
FLOOD FREQUENCY CURVE

4.6 Forebay Pondage

Surface areas of the forebay pond at this intake/diversion weir were measured at different elevations using the 1:2500 scale, two metre contour map developed for the Eastern Brook Area. The nominal full supply level of the intake will be at elevation 72 m and the invert of the penstock will be at 68.5 m. The forebay pondage from elevation 70 m to 72 m will be 10 411 m^3. The total pondage from elevation 68.5 m to 72 m will be 13 897 m^3.

Elevation	Surface Area	Storage El	Storage Volume
68.5 m	885 m^2		
70.0 m	2878 m^2	68.5 - 70 m	2822 m^3
72.0 m	4655 m^2	70 - 72 m	7533 m^3
			10355 m^3

After allowing for required submergance over the intake and for forebay ice thickness, the available pondage is about 3200 m^3. Under minimum inflow conditions, this would allow for about 90 minutes of plant operation at full output. If the forebay level was raised by 2 m (ie. to 74 m), the available storage would allow full plant output for 3.5 hours. As is noted in Section 8 no such peaking operation has been assumed.

Frazil ice and sediment are not expected to be a problem with this arrangement.

4.7 Reservoir Storage

The storage reservoir investigated for this project is situated at Deep Pond approximately 4 km northeast of L'Anse au Clair on Highway 510. This pond has a present

surface area of about 180 000 m^2 with steep clifts rising on its west side and a rolling type of hilly terrain to the east. The storage reservoir would have a surface area of approximately 290 000 m^2 at a dammed height of 8 metres above the present pond water level.

Approximately 55% of the 25 km^2 catchment runs off into Eastern Brook upstream of the planned storage dam location. This means 55% or 11 165 000 m^3 of the catchment's runoff on average could be regulated to maintain a firm flow greater than the natural minimum river flow.

A storage reservoir would increase firm capacity and energy generated by the development, as is further discussed in section 8. Estimated storage volumes investigated were:

Dam Height	Storage Volume
6 m	2 025 000 m^3
8 m	2 700 000 m^3
10 m	3 375 000 m^3

Note: Dam height is the height above the present water level at Deep Pond.

5.0 HYDROELECTRIC DEVELOPMENT

5.1 Alternatives for Development

In the initial assessment stage a variety of schemes were considered. They included run of the river schemes with small intake dams and integrated overflow weirs and larger intake dams with separate spillway structures. Other schemes included reservoir dams of various sizes and construction materials. Different arrangements and routings for the penstock were also considered. After analyzing construction costs versus economic returns a run of the river scheme with an option for a reservoir dam upstream from the intake structure was selected.

During the course of the study, two aspects were identified that had a significant effect on the selection of alternatives. These included a requirement for maintaining flows in the natural stream channel at all times and consideration of a project sized to meet loads in the L'Anse au Clair community only, thereby avoiding a requirement to upgrade the transmission system between L'Anse au Clair and the L'Anse au Loup system to allow three phase transmission.

As a result, two alternative schemes have been developed:

- the reference development that would be optimum in terms of minimizing generation costs, for supply to the overall L'Anse au Loup system, including L'Anse au Clair, and

- a reduced development sized to meet the local L'Anse au Clair load.

As is referred to later, both project sizings or installations would require power to be exchanged between the present three phase system (that extends from L'Anse au Loup to Forteau) and the single phase system that presently supplies power to L'Anse au Clair from Forteau.

Both projects are similar in concept and only differ in respect to the selected installation and corresponding optimum penstock size. Other structures such as the intake/diversion weir and access roads would remain unchanged.

The requirement for fisheries is to assume, at this stage, that at least 25% of the natural runoff in Eastern Brook be provided in the natural stream channel at all times. To meet this requirement, in the assessment of the project, provision has been made for a fish ladder at the intake dam, which has been added as a lump sum cost item to the cost estimate, and estimates of available energy generation have been down-rated by 25%. This reduces the size of the optimum scheme as well as energy benefits.

The sizing of the reduced scheme, essentially to avoid upgrading the existing single phase transmission between L'Anse au Clair and Forteau, has considered 1987 forecast loads in L'Anse au Clair and assumes that power transfers in the order of those presently provided can be accepted, however, in the opposite direction. This is further discussed in Section 8.

For the purpose of developing layouts and costs, the reference scheme has been taken on the optimized development for supply to the L'Anse au Loup system. This project would have an installed capacity of 314 kW. The proposed project arrangements are described in the

following subsections (5.2 to 5.7), while the sizing or optimization of the installation is discussed in Section 8.

The modifications to this basic arrangement for the alternative reduced size project, which would have an installed capacity of 192 kW, are described in Section 5.8.

5.2 Project Layout - 314 kW Scheme

The proposed development will consist of the following main elements:

- A small embankment dam downstream of the confluence of Eastern Brook and Partridge Garden Brook, to provide diversion of stream flows into the penstock intake, together with a free overflow spillway in the right abutment.

- A penstock, 1000 m in length, approximately following the river gradient, which leads to the powerhouse.

- A powerhouse structure and single 314 kW turbine generator set, plus associated electrical/mechanical equipment and switchgear; located about 500 m east of L'Anse au Clair, near the mouth of Eastern Brook.

- A new transmission line between the powerhouse and L'Anse au Clair, plus upgrading of the existing single phase line from L'Anse au Clair to Forteau, to three phase.

The above components form the basic project. The possibility exists of constructing a storage dam at Deep Pond, some 1.6 km upstream of the intake/diversion weir.

This structure has been assessed as a possible addition to the basic project.

The general location of the development is shown in Figure 2.1 and an overall layout is given in Figure 5.1. The individual project structures are described in the following section.

5.3 Access Roads

Powerhouse Access Road

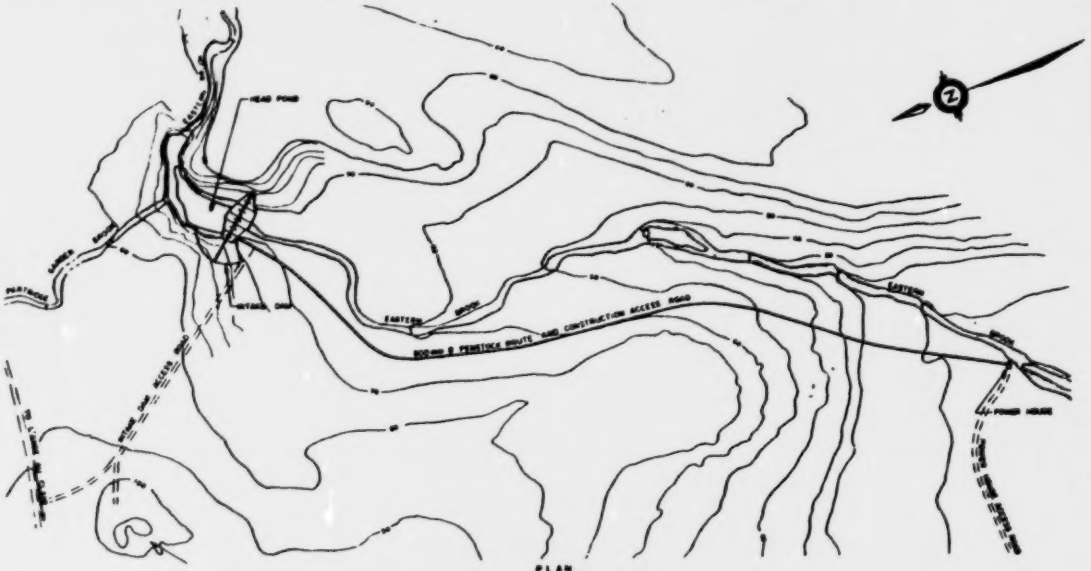
The access road from the edge of the community to the powerhouse will be constructed over an existing trail for a distance of 425 m. It will have a 4 m driving surface and will be constructed entirely of pit run material which is found in the area and presently used by the town for road construction. The route is relatively flat and will not require grubbing. The road will be built by filling over the existing ground.

Intake Dam Access Road

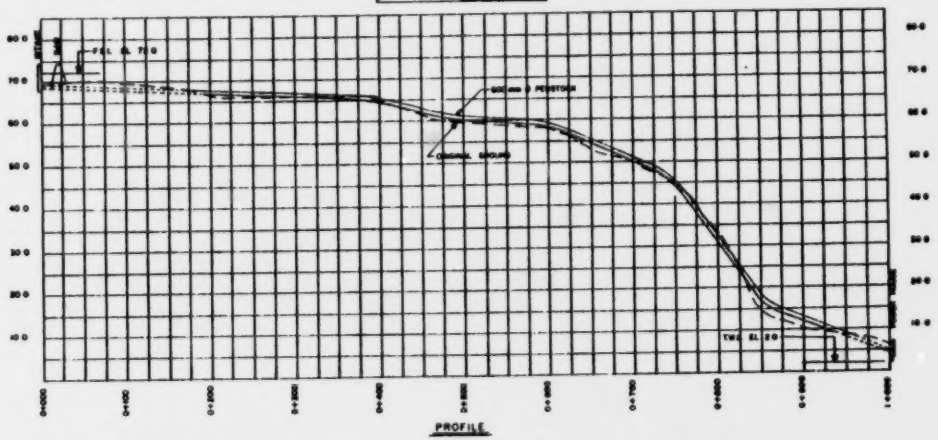
The access road to the intake dam will be 400 m long over a relatively flat barren area from Route 510. Construction material is located at the end of the access road near Route 510. This road will have a top surface width of four metres and will be back filled over the existing ground.

Penstock Access Road

This road will serve a dual purpose. It will be used to transport and lay the penstock but its principle function will be to serve as a foundation bedding for the exposed penstock. It will be a cut and fill construction with a top surface width of 4 m.



PLAN



PROFILE

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GENERAL PROJECT LAYOUT
PLAN AND PROFILE

FIGURE 5-1

Reservoir Dam Access Road

The optional reservoir dam site is located within 100 m of Route 510. A construction access road can be constructed from cut and fill from on-site materials on the southeast bank of the stream.

5.4 Intake Dam

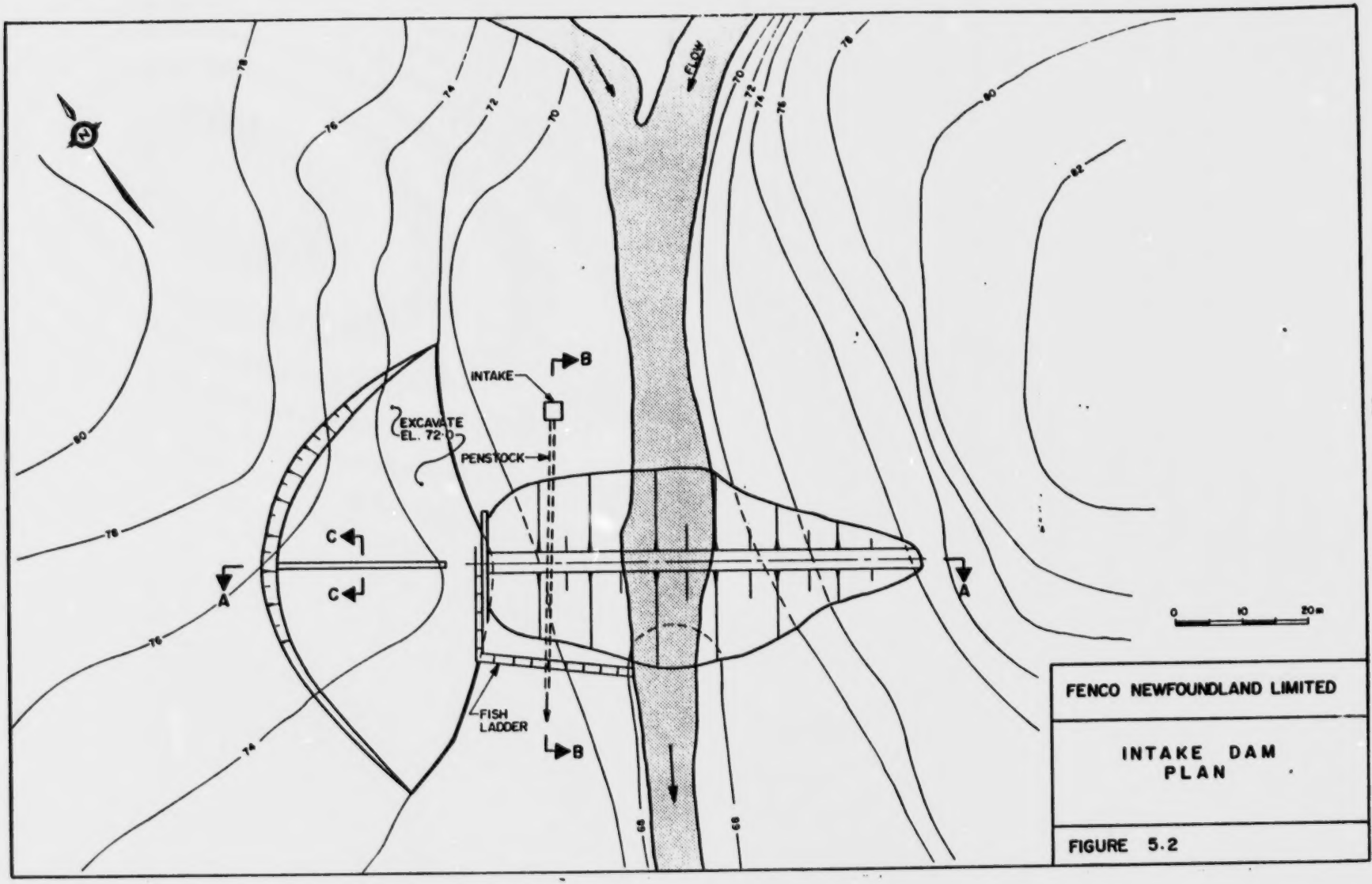
The structure will be located approximately 30 m downstream of the intersection of Eastern Brook and Partridge Garden Brook.

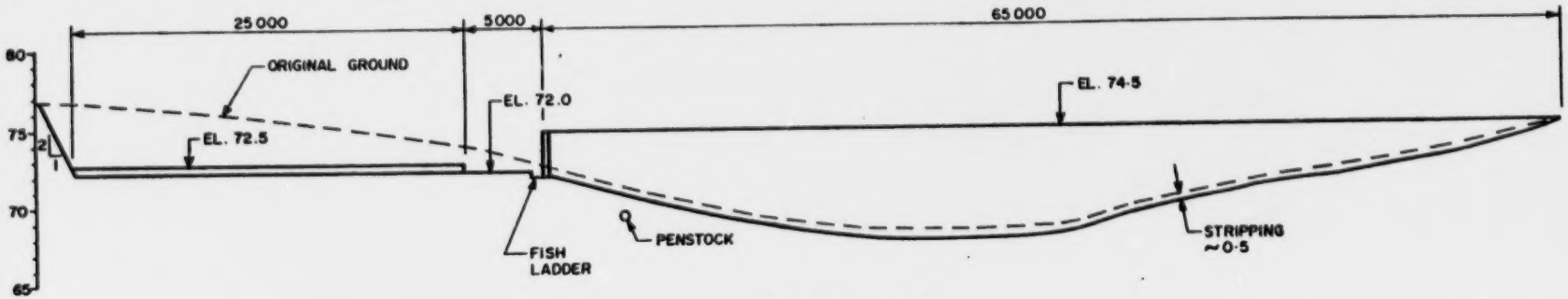
As is shown in Figures 5.2 and 5.3, it would consist of an embankment dam made of compacted till with a 3 m wide crest at elevation 74.5 m and 2H:1V side slopes. Based on the field reconnaissance, it is assumed that it can be founded on rock after approximately 0.5 m of overburden have been removed. The maximum height of the embankment section would be about 7.0 m.

A sand drain would be provided under the downstream toe of the embankment. This drain would also intercept any leakage along the penstock through the fill material. Upstream protection would be provided by a single layer of 200 mm rip-rap that would be placed above elevation 71 m.

The normal full supply level would be at elevation 72.0 m, and the maximum level, with the (1000 year) design flood passing over the spillway, would be 74.0 m.

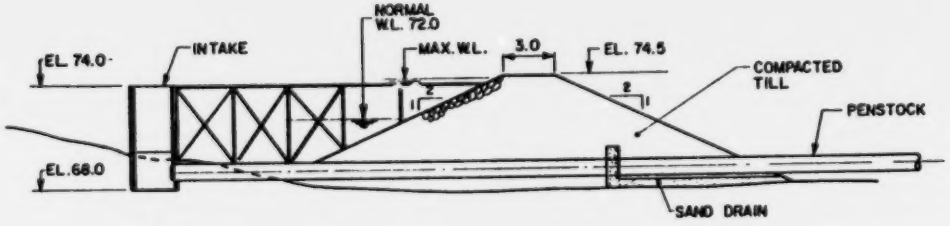
On the right bank, a trench, 30 m in width, would be excavated down to elevation 72.0 m. This trench would serve as the spillway. In order to concentrate small spillway flows, a short section of 5 m is left open.


FLOW
INTAKE
EXCAVATE EL. 72·0
PENSTOCK
FISH LADDER
A
B
C
0
10
20m
FENCO NEWFOUNDLAND LIMITED
INTAKE DAM PLAN
FIGURE 5.2



SECTION -AA-
SCALE 1·250

SECTION -CC-
SCALE 1·50



SECTION -BB-
SCALE 1·250

FENCO NEWFOUNDLAND LIMITED

INTAKE DAM SECTIONS

FIGURE 5.3

Across the remaining 25 m of width, a low concrete crest at elevation 72.5 m is provided.

The right abutment to the embankment section is provided by a reinforced concrete wall with an inclined inside face to provide a positive contact with the fill material.

Immediately adjacent to the wall and in the low section of the spillway crest, a fish ladder would be provided. This essentially will be a shallow chute excavated into the rock with 0.3 m drops along its length. No details have been developed for this arrangement, and to provide a controlled release, however, a lump sum provision has been included in the cost estimate for work in addition to basic excavation.

The intake arrangement consists of a structural concrete box, 2.5 m x 2.5 m with a deck elevation of 74.0 m, with a lateral intake weir at elevation 70.0 m to exclude bed transport, and equipped with racks up to deck level, as well as timber stop logs. A manually operated 900 x 900 mm steel slide gate is provided at the penstock inlet. The head gate would be closed if the penstock is to be dewatered.

Access to the intake for gate operation or rack cleaning would be provided by a walkway from the embankment crest supported on timber piles.

The overall arrangements for the diversion weir and intake is designed for a run-of-the river situation with no forebay pondage. The project evaluation has, therefore, made no allowance for any firm capacity capability. However, the submergence requirements, and the setting of the penstock inlet, as related to the normal forebay, will

allow for some load fluctuations on the unit. Thus assuming zero inflows and 1 m of ice cover, there would be sufficient pondage to allow 1.5 hours of full station output. No evaluation has been made of the economics of providing more pondage by raising the forebay level. However, an increase from 72.0 to 74.0 m would increase the full output time to 3.5 hours.

5.5 Penstock

The length of penstock will be 1000 metres and to ensure turbine stability a 800 mm diameter pipe will be required. After investigating various types of pipe, polyethylene was chosen because of its ability to be placed in service without being buried. This will eliminate the cost of trench excavation, bedding and select backfill material as well as the cost of installing in a trench. The pipe will be joined and placed on top of the penstock access road which will act as the bedding.

Investigations indicate that the winter temperatures experienced in the area will not pose a freezing problem in the penstock while the turbine is operating. In the event that a shut down is required then provisions will be made to drain the penstock through a bypass valve at the powerhouse. Increasing the pipe series along the penstock will accommodate the increase in pressures. The increase in pressures due to water hammer caused by the turbine governor closing has also been considered in the selection of pipe series (wall thickness).

5.6 Reservoir Dam

A small reservoir dam could be located approximately 150 m downstream of Deep Pond. It would be similar in concept to

the intake diversion dam, with a compacted till embankment section and side overflow spillway (as shown in Figure 5.4). The only significant difference is that the spillway requirements are reduced, as the drainage area at the proposed storage dam site is 55% of that at the intake dam. The design flood (1000 year) has, therefore, been selected as 124 m^3/s and the spillway crest width set at 25 m.

The intake arrangements would also be similar except that the outlet would discharge directly into the natural stream channel.

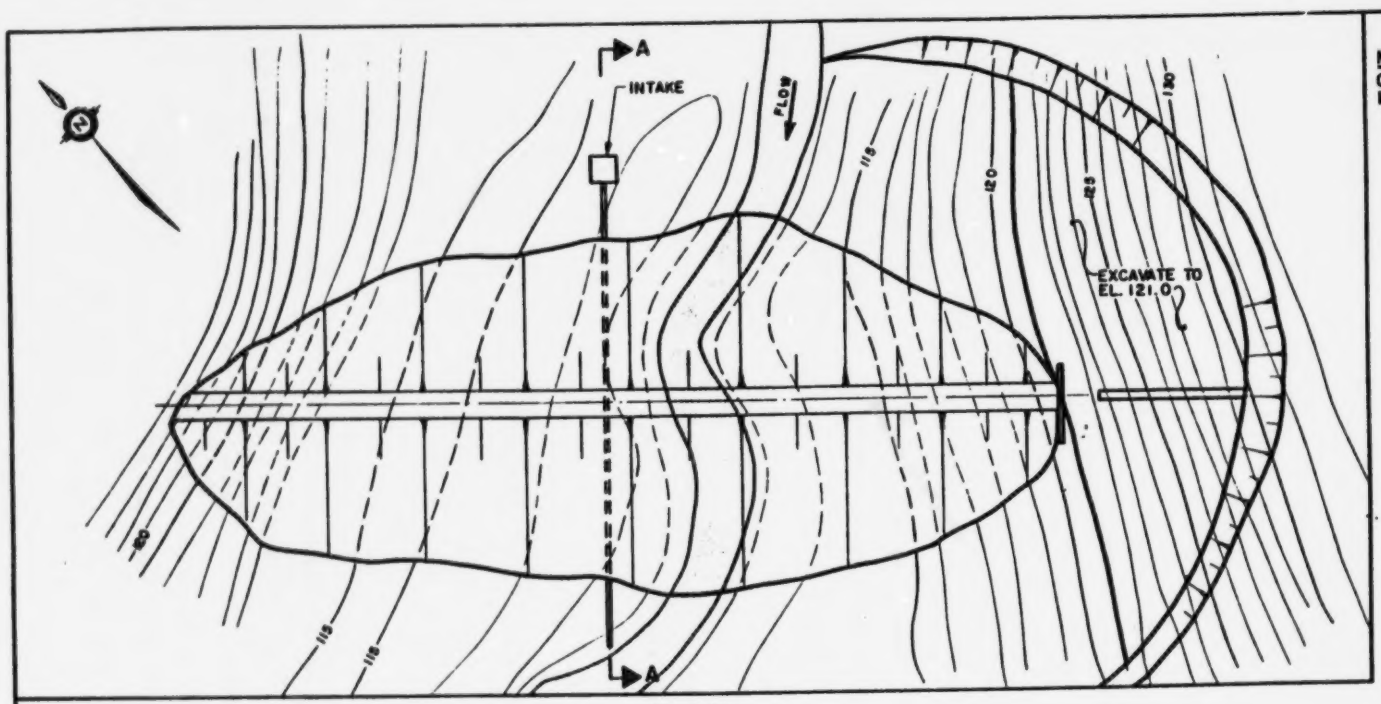
The layout shown in Figure 5.4 is based on a storage height of 6 m above the normal level of Deep Pond, which gives a full supply level of approximately 121.0 m.

Storage benefits and costs have been estimated for live storage heights of 6, 8, and 10 m. The economics of providing storage are discussed in Section 10.

Estimated live storage volumes are as follows:

FSL m	Storage Height m	Storage Volume m
121	6	2 025 000
123	8	2 700 000
125	10	3 375 000

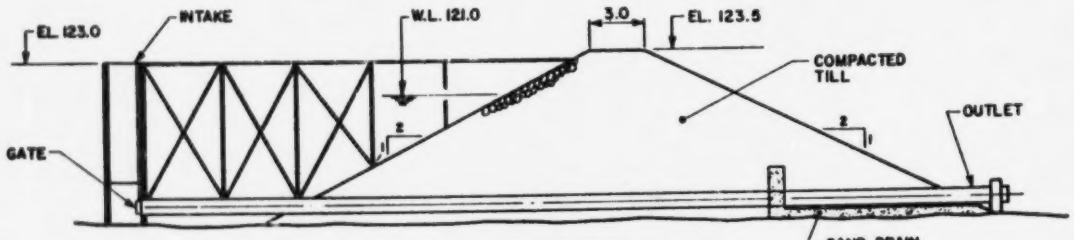
A storage reservoir would increase winter generation and reduce spillage. It would also, depending on the sophistication of the flow release control system, potentially allow full output of the plant at any time, then allowing the full installed capacity to be evaluated as a replacement for future diesel installation.



PLAN
SCALE 1:500 - B

NOTE
Contours are inferred from limited data

0 5 10 m A
0 10 20 m B



SECTION -AA-
SCALE 1:250 - A

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STORAGE DAM
PLAN & SECTIONS

FIGURE 5.4

5.7 Powerhouse

The powerhouse would be located as shown in Figure 5.1, and the general arrangement is shown in Figure 5.5. The structure would house a single horizontal axis turbine generator set and provide sufficient space for plant controls and maintenance.

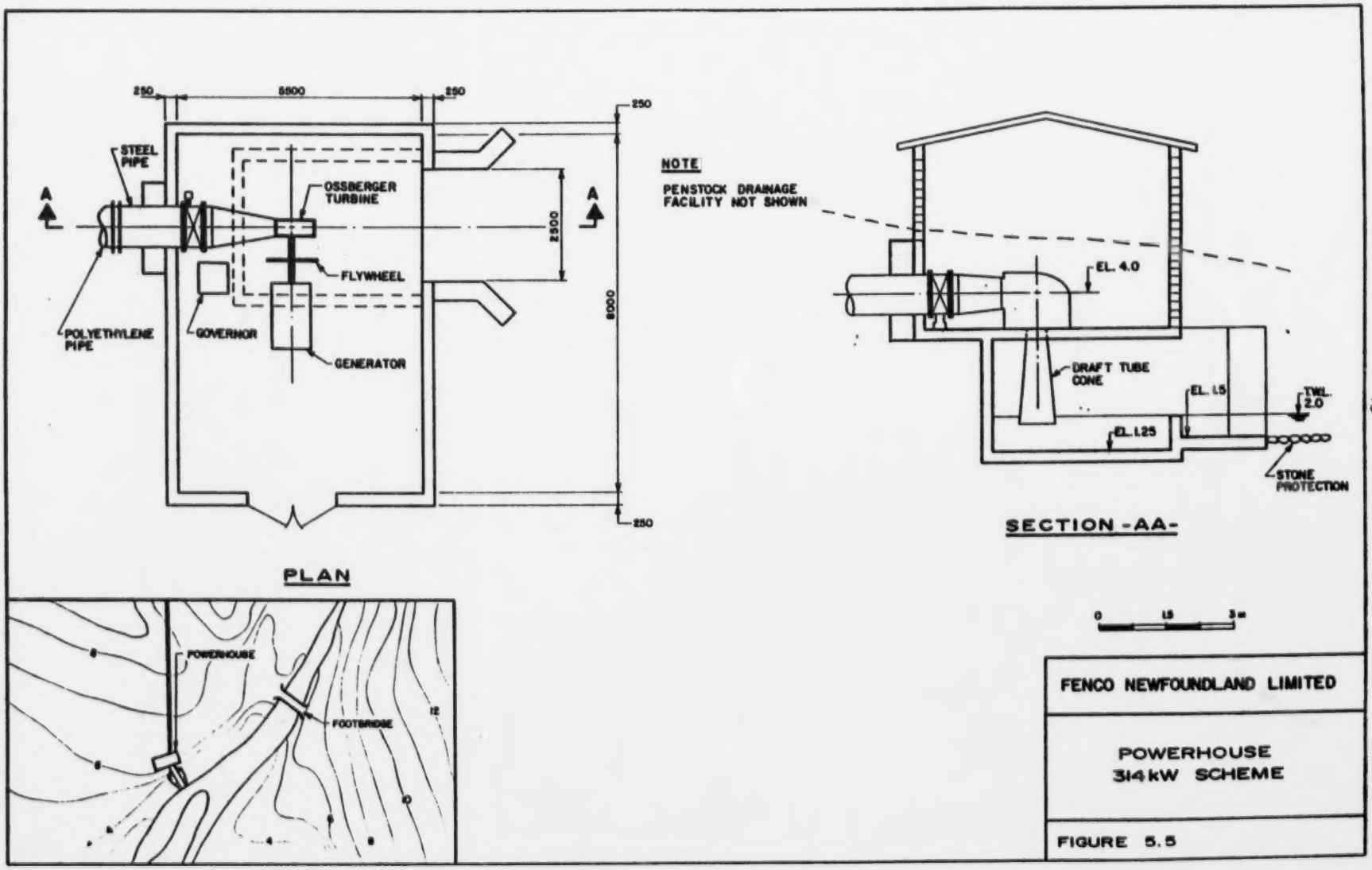
Civil Works

The powerhouse substructure will consist of a reinforced concrete foundation resting on a reinforced concrete slab. The reason for using a slab design versus founding on rock is explained in Section 3.3. The overall dimensions of the structures are approximately 8 x 6 m. The turbine generator centre line is set at 4.0 m and the generator floor would be at elevation 3.5 (as compared with the maximum high water level of 2.0 m). The structure will be located about 20 m from Eastern Brook, about 50 m downstream of the existing footbridge. A short tailrace channel would, therefore, be required, and this would be excavated to the level of the bottom of the draft tube pit, at elevation 1.25 m.

The superstructure would consist of concrete block or metal cladding with conventional facilities for heating and ventilation.

Turbine

The small hydraulic capacity of the schemes, combined with the relatively high expected flow variation, favors the use of an Ossberger (cross-flow) type water turbine which provides a relatively flat efficiency curve from 20 to 100% power and can operate adequately at a power output of 10%.


250
5800
250
250
STEEL PIPE
OSSBERGER TURBINE
A
A
2552
FLYWHEEL
5000
POLYETHYLENE PIPE
GOVERNOR
GENERATOR
250
PLAN
POWERHOUSE
FOOTBRIDGE
12
10
8
6
4
NOTE
PENSTOCK DRAINAGE FACILITY NOT SHOWN
EL. 4.0
DRAFT TUBE CONE
EL. 1.5
TWL 2.0
EL. 1.25
STONE PROTECTION
SECTION -AA-
0
1.5
3 m
FENCO NEWFOUNDLAND LIMITED
POWERHOUSE
314 kW SCHEME
FIGURE 5.5

The selected turbine generator set would have an electrical full output of 314 kW. The turbine would be rated at:

Peak output	443 HP/330.5 kW.
Net head at full output	66.4 m
Plant discharge at full output	0.62 m^3/s

The turbine centreline or axis will be set approximately 2 m above the tailwater elevation at elevation 4 m (M.H.W.L. = 2 m). The turbine is supplied with a draft tube equipped with a vent valve to control the water level in the draft tube and recuperate as much head as possible without exceeding the "wading" limit.

As shown in Figure 5.5, the turbine inlet would also be equipped with a butterfly valve. Facilities for draining the penstock may also be required and a lump sum provision for this has been included in the cost estimate.

Generator

The generator would have a rating of 393 kVa, 600 V, 3 phase, 60 Hz, 720 RPM, 0.80 PF (314 kW).

The design and construction of the generator would be in accordance with ANSI or IEC standards. The windings would be wye connected and the neutral current to an acceptable level.

The excitation system would be of the brushless type utilizing a shaft mounted exiter rotating diodes and a static type voltage regulator. Voltage and current feedback signals would be supplied to the voltage regulators through suitable PT's and CT's.

Station Single-Line Diagram

The station single-line configuration is shown in Figure 5.6.

The station would have a 600 V generator bus and one station service auxiliary bus at 208 V. A 600 V circuit would be provided to feed external facilities. This configuration will allow an inexpensive and reliable source of power for the plant auxiliaries. Main conductors from the generator terminals would reach the 600 V main switchgear close to the control panel, both located indoors.

During plant shutdown, full auxiliary station power would be available from the 12.5 kV line through the main transformer.

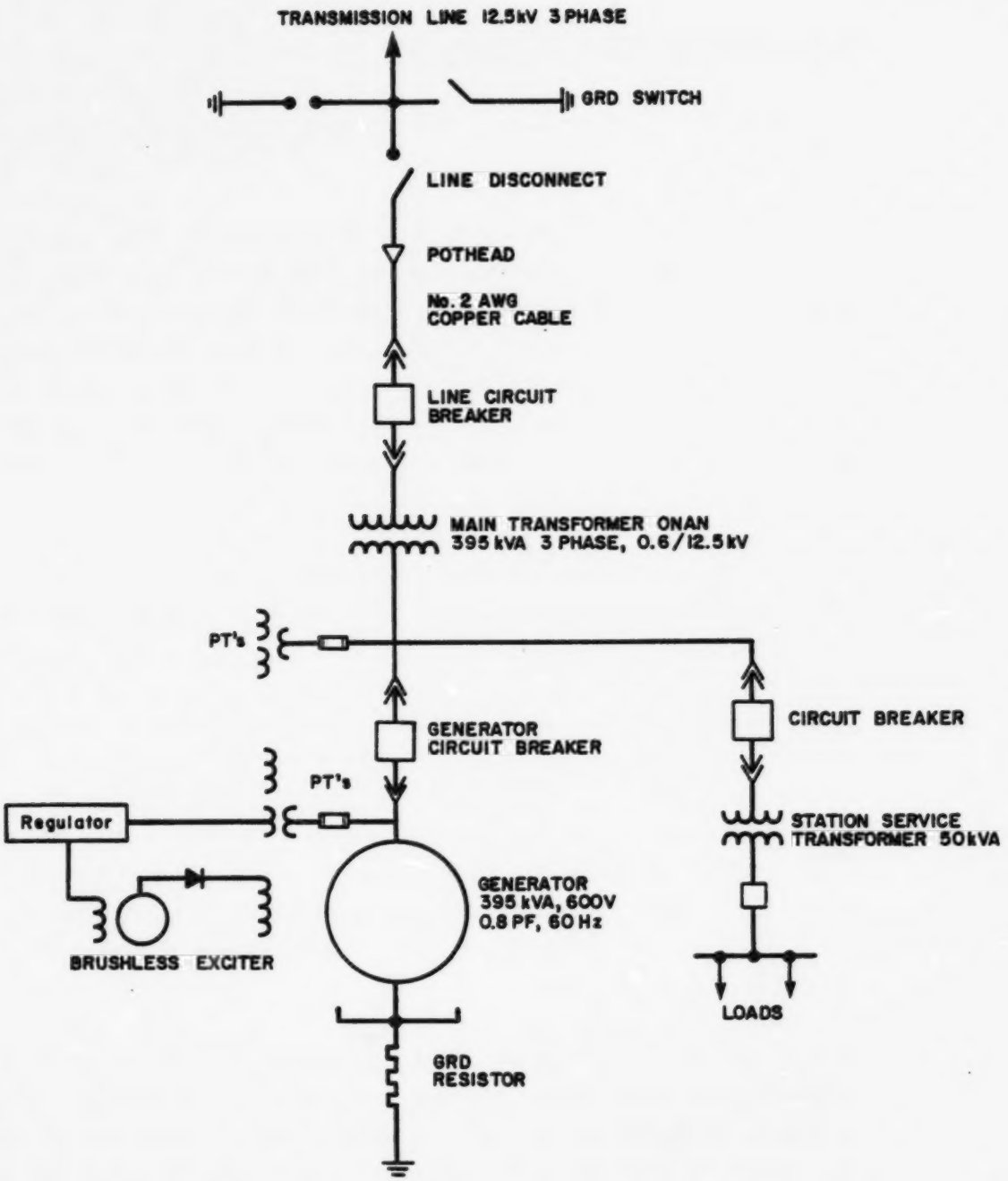
The powerhouse station service auxiliary power would be supplied through a 50 kVA dry-type transformer.

The generator would be connected via the 600 V bus to a 3 phase main transformer rated at 395 kVA. The transformer would be oil immmersed, connected delta primary, Y secondary, with neutral solidly grounded and step-up the power to 12.5 kV level.

A 15 kV #2 AWG copper cable circuit would connect the transformer high side to the line circuit breaker. This circuit breaker would be located indoors and be of the draw-out metalclad type with an interrupting duty of 395 kVA.

A 15 kV cable would connect the circuit breaker to the outdoor line terminal structure with potheads, line switch, and lightning arresters.

FIGURE 5.6



L'ANSE AU CLAIR
SINGLE LINE DIAGRAM
314 kW SCHEME

The present existing 12.5 kV line section from L'Anse au Clair to Forteau is a single phase, No. 2AWG ACSR conductor on mostly concrete poles. To transmit the newly generated power into the L'Anse au Loup system, it will be necessary to convert this line to a 3 phase, 12.5 kV line, utilizing 3 No. 2AWG ACSR (tentatively).

5.8 Alternative 192 kW Scheme

There are two major considerations that may affect the economic and financial viability of the basic 314 kW scheme described above. These are:

- the extent to which transmission upgrading, between L'Anse au Clair and the L'Anse au Loup generation station, would be charged against the hydro project;

- availability of capital investment required to implement an 'off oil' demonstration project.

To some extent, these factors can be minimized by selecting a project that is sized to meet the local L'Anse au Clair load, and thereby both avoid transmission upgrading costs and reduce capital requirements.

Since the detailed analyses required to define transmission requirements for various levels of bi-directional power transfers between the L'Anse au Clair and L'Anse au Loup system are beyond the scope of this study, the size selection for the reduced schemes has been made essentially on the basis of limiting the power transfers more or less to those presently being experienced and to provide an optimum match of installation and penstock size. This is further discussed in Section 8.

The selected reduced alternative scheme would have an installed capacity of 192 kW. It would be identical to the basic scheme except that the penstock diameter would be reduced from 800 mm nominal to 630 mm nominal, and the turbine/generator and ancillary electical equipment would have reduced sizes/ratings. The generator and transformer would be single phase, as would transmission to L'Anse au Clair.

In terms of the cost estimate, the changes are limited to the penstock, equipment and transmission cost. No changes have been made to costs for access, the intake weir/dam (except for minor mechanical equipment cost adjustments) or the powerhouse civil works.

For this alternative scheme, the following equipment ratings would apply:

Turbine

Peak output	271 HP/202 kW
Net head at full output	65.22 m
Plant discharge at full output	0.384 m^3/s

Generator

Rating	240 kVA, 600 V, 1 phase, 60 Hz, 720 RPM, 0.80 PF
Peak output	192 kW

5.9 Transmission

For the basic 314 kW scheme, two sections of transmission will be required.

- A new 3 phase, 12.5 kV line from the powerhouse to L'Anse au Clair, approximately 600 m in length.

- Upgrading of the existing single phase line between L'Anse au Clair and Forteau for 3 phase transmission, with a line length of 10.4 km.

The existing line from L'Anse au Clair to Forteau was constructed in the early 1960's and is now being upgraded to the extent of pole replacement as required.

No assessment has been made of the incremental cost of upgrading this line to carry 3 phase transmission, as it appears that the existing line will, in any case, require extensive work, primarily replacement of poles.

For the purpose of the cost estimate, it has been assumed that the costs to be charged to the project would cover new conductors, cross arms, and insulators. This has been estimated at $20 000/km; as compared with the unit cost of $50 000/km used for the new line section.

Newfoundland and Labrador Hydro have prepared their own estimate of the cost of repairing and upgrading the line between L'Anse au Clair and Forteau. This cost has been estimated at $409 000 at 1984 prices. This is equivalent to $41 000/km (1985). This estimate for the complete cost of line upgrading has not been used in the project assessment because of uncertainty in the amount that should be charged against the project.

The estimate of transmission costs included for the 192 kW scheme includes only the new line from the power station to L'Anse au Clair, assumed at $50 000/km or $30 000 total.

6.0 CONSTRUCTION

6.1 Schedule

Since a project release date is not known a start time of April 6, 1986 has been assumed for construction schedule (see Figure 6.1). A start date at this time will be essential to allow enough lead time on the manufacturing and delivery of the turbine and generator if the project is to be completed in 1987. The actual on site construction will be completed in five and one half months.

The project can be completed and power supplied to the grid by November 1, 1987 provided the following schedule is adhered to:

- Access road constructed to the powerhouse mid-May to the end of May, 1987.

- Excavation for powerhouse, and tail race and powerhouse construction - beginning of June to the end of September, 1987.

- Access road to storage dam and storage dam construction - beginning of June to mid-October, 1987.

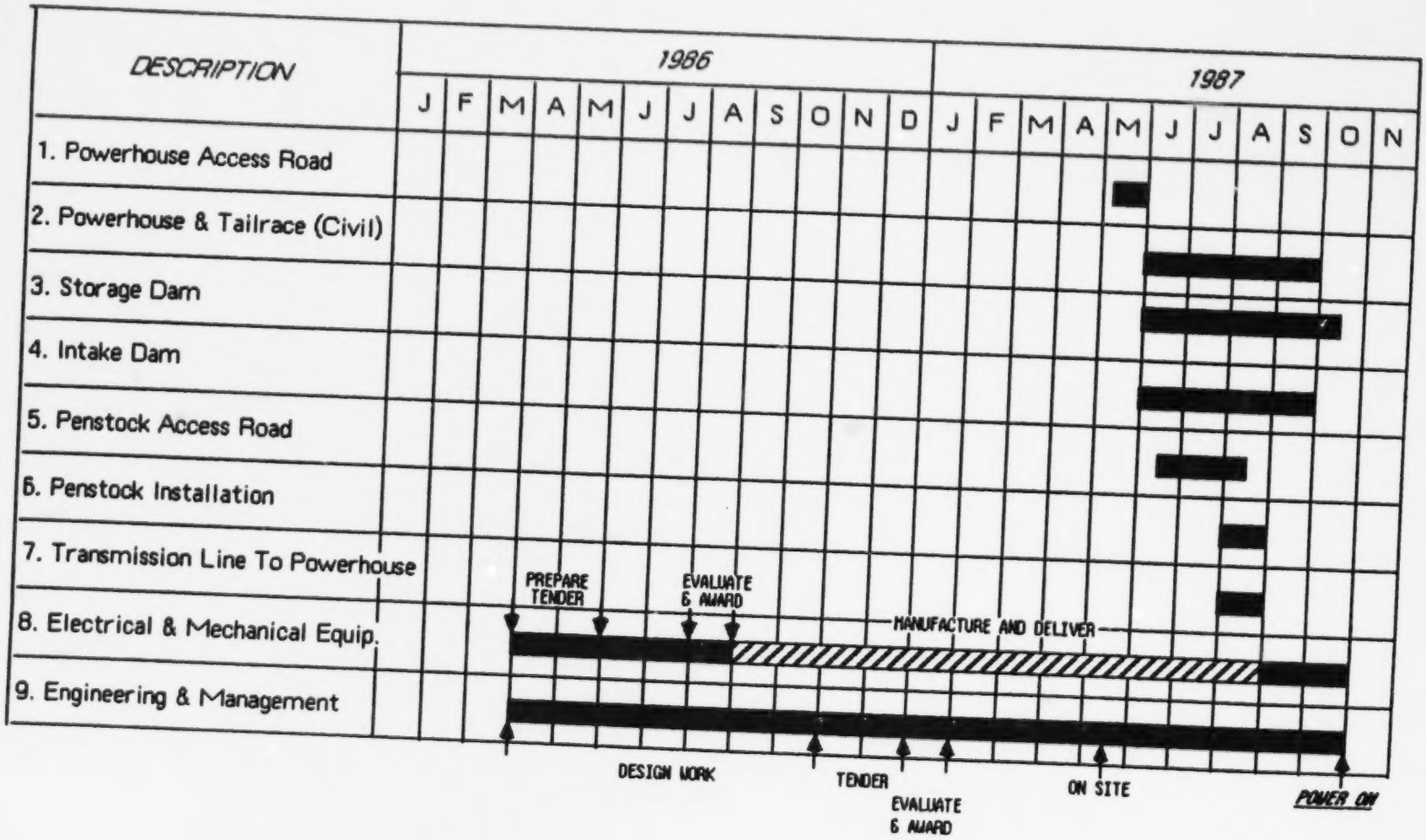
- Access road to intake dam and dam construction - beginning of June to end of September, 1987.

- Penstock access road and stream crossing - middle of June to the middle of August, 1987.

- Installation of penstock - beginning of August to the end of August, 1987.

L'ANSE AU CLAIR MINI–HYDRO PROJECT
CONSTRUCTION SCHEDULE

Figure 6.1



- Transmission line to the powerhouse - beginning of August to the end of August, 1987.

- Electrical and mechanical equipment for the powerhouse - early September to end of October, 1987.

6.2 Contracts

The proposed construction schedule calls for two supply contracts and two construction contracts.

Contract 1

Contract 1 will include the designed supply of the turbine generator unit. This unit will include the turbine, draft tube, speed increaser, flywheel and governor. A 12 month manufacture and delivery period is required for these units.

Contract 2

Contract 2 will include the supply and erection supervision of 1000 m of 800 mm diameter polyethylene pipe for the penstock. Tenders will be called for the supply in late February or early March of 1987 so as to allow for delivery on site by mid-August.

Contract 3

Contract 3 will include all of the required civil work plus the associated mechanical and electrical work.

The civil work will include but not be limited to the construction of access roads, intake dam and associated work, excavation and construction of powerhouse,

installation of penstock, and installation of turbine and generator.

Contract 4

Contract 4 will include all civil and electrical work associated with transmission line and substation construction.

Contract Packages

Contract	314 kW	192 kW
1. T/G equipment	$239 400	$179 400
2. Pipeline	394 000	274 000
3. Civil Works	375 160	370 960
4. Transmission	240 000	30 000

Note:

1. An additional 5% should be added to Contracts 1, 2, and 3 to cover indirect construction/supply costs.

2. Contract 4 includes all overheads.

6.3 Manpower

Much of the work skills required for the project such as equipment operators, carpenters and labourers should be available from the labour pool in the immediate vicinity. Supervisory staff, skilled operators and other essential personnel will most likely be brought in by the contractor An estimate of manpower requirements for the basic 314 kW scheme is 150 man months, excluding transmission and storage dam.

7.0 CAPITAL COST ESTIMATE

7.1 Basis of Estimate

Quantities for capital cost estimates were calculated from plans and profiles surveyed in the field, 1:2500 mapping especially prepared for this study, aerial photographs, and existing 1:50 000 maps.

Unit prices applied to the estimated quantities are based on real and projected 1985 prices and were obtained from the following sources.

- Information on construction projects being carried out in Newfoundland and Labrador as supplied by contractors, other consultants and government departments.

- Information from the consultant's files and experience with similar construction in Newfoundland and Labrador and other areas of Canada.

- Quotations from suppliers capable of supplying the required materials.

- Statistical information on electrical and mechanical equipment costs.

Costs exclude any allowance for escalation or interest during construction. Conventional allowances are included for overhead expansion and contingencies. The contingency amount is to cover unforeseen costs and does not allow for uncertainty in the cost estimates.

7.2 Capital Cost

Basic 314 kW Scheme

The capital cost for the complete run-of-the-river project is estimated as:

Hydro Project	$1 339 640
Transmission	240 000
Total	$1 579 640

Reduced 192 kW Scheme

The capital cost for the reduced scheme is estimated as:

Hydro Project	$1 094 920
Transmission	30 000
Total	$1 124 920

These costs are summarized in Table 7.1 overleaf and are detailed in Appendix 4.

TABLE 7.1

CAPITAL COST SUMMARY

Item	314 kW	192 kW
1. Access Roads	$ 97 000	$ 97 000
2. Intake Dam	179 900	175 700
3. Penstock	394 000	274 000
4. Powerhouse Civil	98 260	98 260
5. Powerhouse Electrical/ Mechanical	239 400	179 400
SUB-TOTAL	$1 008 560	$ 824 360
Indirect Construction Cost (5%)	50 430	41 220
SUB-TOTAL	1 058 990	865 580
Engineering and Owners Cost (15%)	158 850	129 840
SUB-TOTAL	1 217 840	995 420
Contingencies (10%)	121 800	99 500
Hydro Project Total	$1 339 640	$1 094 920
Transmission	240 000	30 000
PROJECT TOTAL	$1 579 640	$1 124 920

8.0 POWER AND ENERGY

8.1 Existing Loads, Load Forecasts and Power Supply

Details of the L'Anse au Loup system and historical data on demand and performance including costs were provided by the Power Distribution District of Newfoundland and Labrador Hydro (Appendix 5).

The present energy system at L'Anse au Loup consists of four diesel generators (850 kw, 600 kw, 600 kw, 800 kw) with a total capacity of 2850 kw and a firm capacity of 2000 kw. A transmission system runs south to L'Anse au Clair and north to Red Bay providing electricity for 11 communities.

The net energy sales of the L'Anse au Loup generation system in 1983 was 6860 MWh. The peak load for that year was 1680 kw. Table 8.1 shows the forecasted loads for this distribution system.

The three largest users of electricity are L'Anse au Loup, Forteau, and L'Anse au Clair in that order. L'Anse au Clair's portion varies slightly around 14% (1983 records).

The following figures and tables describe the load characteristics for L'Anse au Clair and the whole L'Anse Au Loup generating system in 1983, and provide a load forecast for the total L'Anse au Loup system.

Table 8.2 - Sales Summary Report, L'Anse au Loup, 1983.
Table 8.3 - Sales Summary Report, L'Anse au Clair, 1983.

The study of the reduced 192 kW scheme also includes consideration of loads in L'Anse au Clair only. These were

TABLE 8.1 Forecast for L'Anse au Loup Distribution System

Year	MWh	% Increase	kw	% Increase
(Actual) 1983	6 860		1 680	
(1) 1984	7 227	5.3	1 764	5.0 (1)
(1) 1985	7 574	4.8	1 855	5.2 (1)
(1) 1986	7 878	4.0	1 935	4.3 (1)
(1) 1987	8 195	4.0	2 018	4.3 (1)
(1) 1988	8 525	4.0	2 104	4.3 (1)
(1) 1989	8 866	4.0	2 194	4.3 (1)
(2) 1990	9 221		2 288	
(2) 1991	9 589		2 387	
(2) 1992	9 973		2 489	
(2) 1993	10 371		2 596	
(2) 1994	10 787		2 708	
(2) 1995	11 218		2 825	
(2) 2000	13 648	(annually)	3 487	

Note: (1) Forecast provided by Newfoundland and Labrador Hydro

(2) Extended to year 2000 at 4% energy and 4.3% capacity annual growth.

(3) Loads for L'Anse au Clair are assumed as 14% of the total in 1983 and are assumed to increase by 4% annually, for both energy and capacity.

TABLE 8.2 PDD Customer Service

Sales Summary Report for L'Anse au Loup, 1983

SALES				PRODUCTION						
DATE	CUSTOMER	KWH's	12-MTD-KWH	KWH's	DEMAND	12-MTD-KWD	STA-SRV	CO-USE	LOSSES	MLF
8301	722	501,783	5,392,925	556,800	1,608	6,038,400	65,040	0	10.68	.46
8302	720	445,857	5,388,748	470,400	1,488	6,031,200	36,240	0	10.65	.47
8303	723	420,929	5,380,964	501,600	1,536	6,048,000	39,440	0	11.12	.43
8304	724	438,131	5,404,712	484,400	1,416	6,100,800	50,520	0	11.40	.47
8305	724	453,289	5,447,639	533,800	1,488	6,154,600	44,400	0	11.48	.48
8306	729	533,606	5,524,984	518,400	1,512	6,185,800	36,480	0	10.68	.47
8307	726	504,108	5,575,715	571,200	1,418	6,217,000	35,400	0	10.81	.54
8308	730	524,063	5,629,740	542,400	1,512	6,250,600	34,920	0	9.83	.48
8309	730	504,600	5,682,421	516,000	1,488	6,265,000	33,120	0	9.25	.48
8310	734	463,423	5,703,961	528,000	1,560	6,284,200	35,880	0	9.23	.45
8311	735	475,675	5,747,887	506,400	1,488	6,293,800	38,400	0	9.67	.47
8312	740	531,879	5,797,343	624,000	1,680	6,353,800	46,440	0	8.75	.49

TABLE 8.3 PDD Customer Service
Sales Summary Report for L'Anse au Clair, 1983

Month	Domestic Use	0-10 kw	10-100 kw	Street and Area Lighting	Monthly Totals	% of Total System Demand*
JAN.	58,290 kwh	12,607 kwh	10,300 kwh	1,386 kwh	82,583 kwh	14.8
FEB.	51,950	11,905	8,080	1,386	73,321	15.6
MAR.	47,232	10,610	6,960	1,386	66,188	13.2
APR.	51,959	10,957	8,380	1,386	72,682	15.0
MAY	42,417	8,711	10,260	1,386	62,774	11.7
JUNE	53,497	14,949	16,080	1,386	85,912	16.6
JULY	41,218	11,200	13,580	1,386	67,384	11.8
AUG.	47,839	11,190	16,020	1,386	76,435	14.1
SEPT.	51,022	11,183	15,280	1,386	78,871	15.3
OCT.	47,407	9,617	13,400	1,386	71,810	13.6
NOV.	48,411	8,323	11,240	1,386	69,360	13.7
DEC.	53,906	10,739	12,540	1,386	78,571	12.6
TOTAL	595,148	131,991	142,120	16,632	885,891	14.0
MEAN	49,596	10,999	11,843	1,386	73,824	

*This column shows the L'Anse au Clair monthly demand as a percentage of the L'Anse au Loup system monthly demand.

based on 1983 actuals (14% of the total L'Anse au Loup load) and were increased by 4% annually to provide a provisional load forecast.

8.2 Energy Estimates

The energy generation capability of the proposed project for a range of installations was estimated to meet the following requirements:

- to provide information on energy generation capability as a function of installed capacity for use in the optimization studies;

- to define the generation capability of the alternative schemes;

- to define benefits associated with possible upstream storage development.

As described above the basic hydrologic or streamflow information used for assessment of the L'Anse au Clair project is the recorded streamflow sequences for the St. Paul River, Quebec Station 076601, adjusted for the estimated Eastern Brook runoff rainfall ratio.

The basic energy estimates were obtained from an estimated duration curve of daily flows for Eastern Brook. This was obtained by prorating the ordinates of the daily flow duration curve for St. Paul, which was based on recorded daily flows for the period August 1967 to September 1975.

The relationship used was

$Q_{St.\ Paul} \times K = Q_{Eastern\ Brook}\ m^3/s$

where $K = 0.004426$

The value of K reflects the ratio of drainage areas, 25 km^2 to 6632 km^2, and the higher relative runoff from rainfall estimated for Eastern Brook as compared with the St. Paul River.

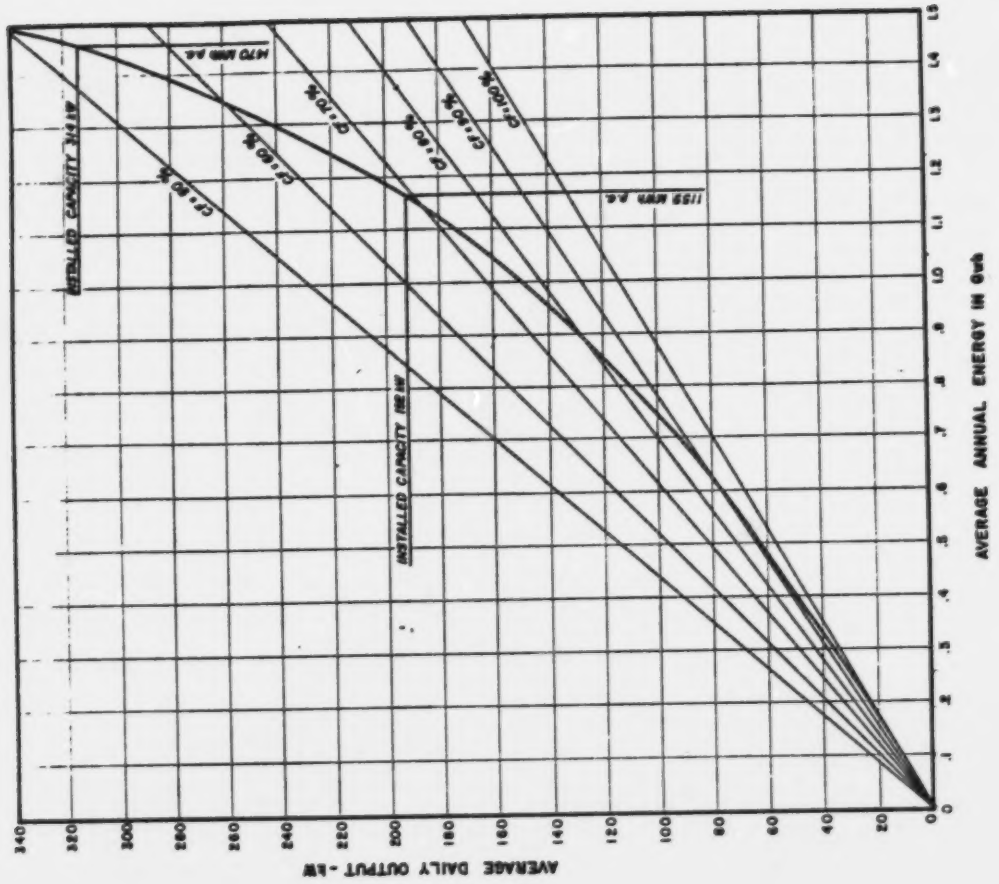
The Federal Department of Fisheries and Oceans have set a requirement, for this stage of the project investigations, that no more than 75% of the natural stream flow of Eastern Brook may be diverted out of the natural channel at any time. The reasons for this are outlined in Section 9.

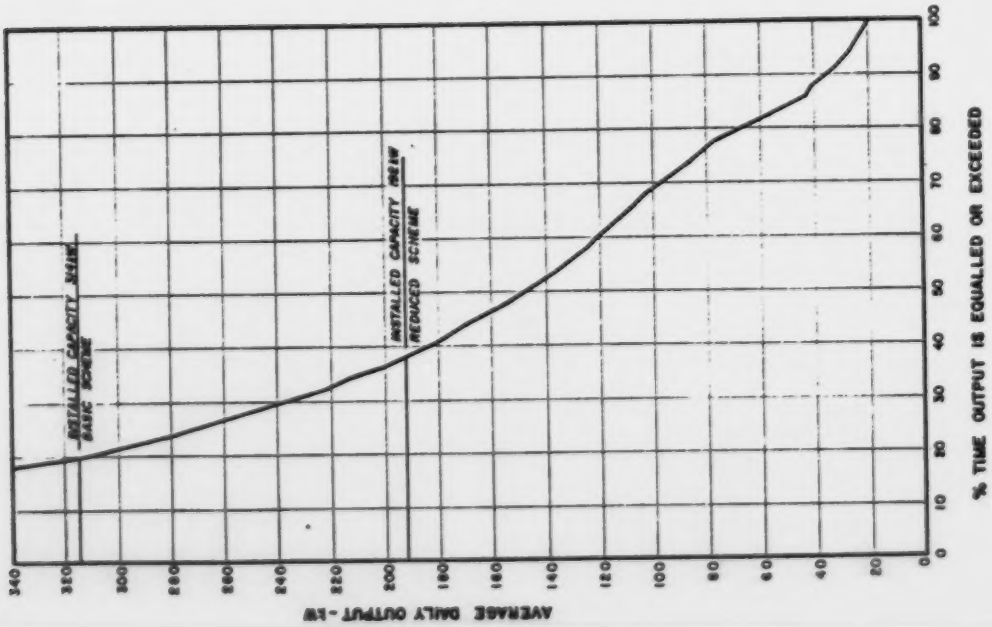
For the purpose of preparing energy estimates, the flow available for power at any time was taken as 75% of the runoff. Thus, in effect, the ordinates of the daily flow duration curve were reduced by 25% and a modified duration curve was developed.

The power duration curve corresponding to a 800 mm diameter pipe scheme is shown in Figure 8.1, together with the integral of the curve. Installations and annual energy values for the 314 and 192 kW schemes are indicated. (It should be noted that the 192 kW scheme would incorporate a 630 mm diameter penstock. The energy value, indicated in Figure 8.1, is based on the power duration curve for that scheme).

The effect of pipeline size and hence head losses on the average energy values is shown by the following comparison, based on flows equaled or exceeded for 40% of the time.

FIGURE 8.1


AVERAGE DAILY OUTPUT - MW
AVERAGE ANNUAL ENERGY IN Gwh
INSTALLED CAPACITY 340 MW
INSTALLED CAPACITY 280 MW
1175 MWh P.F.
1070 MWh P.F.
C.F. 80 %
C.F. 60 %
C.F. 50 %
C.F. 40 %
C.F. 30 %
C.F. 10 %


AVERAGE DAILY OUTPUT - MW
% TIME OUTPUT IS EQUALLED OR EXCEEDED
INSTALLED CAPACITY 340 MW
BASE SCHEME
INSTALLED CAPACITY 280 MW
REDUCED SCHEME

Pipe Size mm	Maximum Daily Output at Q40	Average Energy MWH p.a.
630	176	1106
710	181	1129
800	184	1142
900	185	1149
1000	186	1152

The daily power duration curves for the L'Anse au Clair project were estimated by applying appropriate coefficients to convert flow to usable power output (ie., after allowing for transmission losses). The formula used was:

$$kW = 9.806 \times 0.82 \times 0.95 \times 0.97 \times Q \times H$$

where

Average turbine efficiency is	0.82
Average generation efficiency is	0.95
Transmission efficiency	0.97

Q is the available daily flow in m^3/s
H is the net head in metres.

Thus, power output as a function of flow and head is given by:

$$kW = 7.41\ Q \times H.$$

The basic scheme includes a 1000 m long penstock. The overall head loss is directly a function of pipeline size, available flow (assuming run-of-the-river operation where plant flow and river flow, up to the capacity of the plant, is equal at any time). The available net head, as a function of plant flow is given by:

$Hn = 70 - kt\ Q^2$

where Hn = net head (metres)
70 = available gross head (metres)
Q = plant flow m^3/s
kt = coefficient

The head loss includes the intake, penstock, and velocity head loss, and as a function of pipe size are as follow:

HEAD LOSS COEFFICIENTS

Pipe Size mm	Pipe Loss Kp	Other Losses Ko	Total Kt
630	28.88	1.67	30.55
710	15.30	1.03	16.33
800	8.11	0.64	8.75
900	4.36	0.40	4.76
1000	2.86	0.27	2.83

Pipe Size and Installed Capacity

The optimization studies considered a series of installed capacities. For each of these, there is an optimum pipeline diameter. For this study, the criterion in defining optimum is that the selected size will result in least cost generation.

With regard to the selection of pipeline size, for any given installed capacity there are two factors to be considered:

- maximum velocities in the pipeline
- minimizing generation costs.

During the first part of the studies, it was determined that the maximum acceptable velocity in the pipe was 1.6 m/s. For this velocity, the maximum pressure rise would be 27%, and the maximum speed rise 41%. Higher velocities would result in difficulties in designing the system to maintain stable operation and frequency control. This maximum velocity of 1.6 m/s was adopted for all pipeline sizes considered.

For each pipeline size, the component of the averge energy unit generation cost attributable to the pipeline was determined for a range of installations ranging (in terms of flow on the duration curve) from Q10 to Q30. The direct pipeline cost was increased by 32.8% to cover the overheads shown in Section 7. Annual pipeline costs were calculated in the same way as the total unit generation costs shown in Section 10.2. Average annual energy values for each pipeline size and duration curve flow values were obtained directly from the integral of the power duration curve for each pipeline size.

The results of the comparison of the pipeline component of the unit generation costs showed that, irrespective of installation size, and within the range of pipe sizes shown, least cost generation will result from adopting a minimum pipe size. Thus, the incremental benefits, in terms of reduced losses, from increasing the pipe size are less than the corresponding increase in costs.

Pipeline Component of Generation Cost (Cents/KWH)

Pipe Size mm	Q10	Q14	Q24	Q30
630	2.81	2.78	2.96	3.14
710	3.08	3.15	3.52	3.76
800	3.40	3.54	4.04	4.86
900	3.93	4.12	4.76	5.14
1000	4.47	4.72	5.47	5.91

The above unit costs are based on:

Interest Rate	10%
Plant Life	35 years
Insurance	0.10% of Capital Cost
Interim Replacement	0.22% of Captial Cost

By comparison, the maximum velocity criterion limits the pipeline diameters as follows:

Maximum Installed Capacity vs Pipe Size

Pipe Size mm	Max Flow m^3/s	Max Power KW	Time on Duration Curve in %
630	0.396	191.3	36.1
710	0.502	245.2	27.5
800	0.638	314.1	21.0
900	0.805	399.1	15.5
1000	0.983	492.7	11.0

It should be noted that the adopted polyethylene pipe is available in standard diameters, of which the above sizes are part of the available range. Thus, each pipe size may be associated with a single optimum plant installation.

Average Energy

The optimization study to select the plant installation therefore compared generation costs for the above alternatives.

For each installation and associated pipeline size, the following average energy values were obtained from the power duration curves.

Average Energy vs Installed Capacity

Installation KW	Average Energy MWH p.a.
192	1159
245	1316
314	1470
399	1608
493	1723

Firm Energy

The firm energy capability estimated for the project is based on the minimum daily derived flow based on the recorded daily flow sequence for the St. Paul River and for the period 1967 to 1975.

The minimum daily flow at Eastern Brook is estimated as 0.055 m^3/s. After allowing for the fisheries flow release, the minimum flow is 0.042 m^3/s. For the basic 314 kW scheme, this corresponds to a nominal minimum output of 21.4 kW. The annual firm energy value is therefore 21.4 kW x 8760 or 187 000 kWh. (See also Section 8.4)

Firm energy values for the alternative installations tested in the optimization studies, with their associated different penstock sizes, are virtually the same as head losses at the low flows are insignificant.

8.3 Selected Installations

Basic Project for Supply to L'Anse au Loup

The selection of the preferred installed capacity for the project was based on an optimization study. This analysis considered relative costs and benefits for the five alternative installations schemes in the previous section.

As described in Section 5, the overall project consists of three main elements:

- diversion dam and intake, which is a fixed cost component, irrespective of the selected installation;
- 1000 m of surface penstock, for which the size and cost is directly a function of installation and plant flow;
- powerhouse, turbine/generator and associated electrical and mechanical equipment, for which costs are also directly a function of installation.

For the optimization analyses, average energy and capital cost estimates were prepared for each of the installations. The comparisons considered two sets of costs. The upper estimate was based on a very conservative (or high) cost for the powerhouse generating equipment, and the lower estimate assumed a lower limit for these costs. The costs for all other elements were kept the same. Also, for these comparisons, transmission costs were excluded, as it was assumed that they would be essentially the same for all alternative installations.

Optimization Study - Capital Costs vs Capacity

Installation KW	Average Energy MWH (1)	Capital Cost $,000 Upper	Lower
192	1159	1258.9	1033.2
245	1316	1413.0	1151.4
314	1470	1573.7	1266.9
399	1608	1766.2	1409.0
493	1723	1957.5	1549.8

(1) After 3% transmission losses

It is relevant to note that the final estimated capital costs for the 314 kW and 192 kW schemes were between the upper and lower limits, as follow:

192 kW	$1 094 900
314 kW	1 339 600

The selection of the optimum installation was based on comparison of unit generation costs. These were calculated using the same criteria that were used in the final estimates of generation costs (Section 10.2). The

criterion used to identify the optimum installation was that average generation cost should be minimum.

Unit generation costs were calculated for each installation, for the upper and lower capital costs, and for interest rates between 8 and 14%. It may be noted that this analysis excludes any allowance for escalation. Consequently, the range of interest rates used as the basis for size selection is equivalent to a range of about 12 to 18%, if escalation effects had been added.

The comparison of generation costs indicated that the following installations would be optimum depending on the decision interest rate and cost estimate range.

Installed Capacity Selection

Interest Rate %	Upper Cost Range	Lower Cost Range
8	399	399
10	314	399
12	314	399
14	314	399

This above comparison shows that either the 314 kW or 399 kW scheme could be selected. For the purpose of this study, the 314 kW installation has been used for the reference or basic scheme, assuming supply to the L'Anse au Loup system.

The selected scheme has the following main charateristics:

Installed Capacity	314 kW
Average Energy	1 470 000 kWH p.a.
Capacity Factor	53.4%
Net Head at Full Output	66.4 m
Maximum Plant Flow	0.62 m^3/s
Penstock Size	800 mm

Reduced Project for Supply to L'Anse au Clair

The alternative concept for the project is that it would be sized so that the existing single phase transmission in L'Anse au Clair itself would not have to be upgraded to three phase, thereby avoiding significant additional costs. A further advantage from a smaller scheme is that the reduced capital cost may make it a more probable project for financing as a demonstration program.

The present peak capacity and energy demands in L'Anse au Clair are about 14% of the total L'Anse au Loup system. For the purpose of this analysis, the local loads in L'Anse au Clair have been estimated for 1987, the earliest on-power date for the project, as the 1983 demands, capacity and energy, at 14% of the total, and escalated by 4% annually. This load growth rate is arbitrary and marginally less than that expected for the total L'Anse au Loup system. The resulting 1987 demands for L'Anse au Clair are:

Peak Capacity	275 kw
Average Energy	1036 MWH

The general criteria for the selection for the reduced size scheme have assumed that the project output should approximately match the local L'Anse au Clair load and that bi-directional power transfers with the L'Anse au Loup system should be in the same order as those now experienced.

It is noted that the present arrangement provides power to L'Anse au Clair from one phase at Forteau. Thus, it is assumed that this load inbalance is, at least in part, compensated by offsetting single phase takeoffs. Thus, the presently, more or less, balanced system could not necessarily absorb a power infeed in the L'Anse au Clair circuit equivalent to the present outgoing supply.

Under the present arrangements, the peak power supplies to L'Anse au Clair are approximately:

Peak	235 kW
Energy	85 MWH per month (peak month)

It is recognized that any hydroelectric facility would result in bi-directional power transfers. However, examination of the derived generation data for the various installations already considered shows that the 192 kW scheme would probably meet the overall criterion of avoiding transmission upgrading.

Assuming that the hydro project is installed at 192 kW, and with its associated 630 mm pipeline, the month by month capacity and energy balance for 1987 will be as shown in the table overleaf. This shows that, in an average water year, the peak capacity deficit or demand would be reduced from 275 kW to 183 kW and that the maxmum energy surplus, to be input to the three phase system, would be 67 MWH per

month, as compared to the present transfer from L'Anse au Loup to L'Anse au Clair of 85 MWH per month.

On this basis, the reduced scheme is assumed to have an installed capacity of 192 kW. The primary characteristics of this reduced size scheme are therefore:

Installed Capacity	192 kW
Average Energy	1 159 000 KWH p.a.
Capacity Factor	68.9%
Net Head at Full Output	65.2 m
Maximum Plant Flow	0.384 m^3/s
Penstock Size	630 mm

In the selection of this size for the reduced scheme, it is to be recognized that the analyses required to confirm the maximum installation that would avoid the need to upgrade the transmission system between Forteau and L'Anse au Clair are beyond the scope of this study. Also, that a smaller project would result in increased generation costs, and that a larger installation would reduce costs.

ENERGY BALANCE 1987 - AVERAGE WATER YEAR

Month	Hydro Generation		L'Anse au Clair		Deficit/(surplus)	
	Peak kW	Energy MWH	Peak kW	Energy MWH	Peak kW	Energy MWH
Jan.	81	59	264	97	183	38
Feb.	73	53	244	86	171	33
Mar.	70	51	254	77	184	26
Apr.	85	62	234	85	149	23
May	192	140	245	73	53	(67)
June	192	140	249	100	57	(40)
July	192	140	234	79	42	(61)
Aug.	192	140	249	89	57	(51)
Sept.	192	140	245	92	53	(48)
Oct.	192	140	257	84	65	(56)
Nov.	186	136	245	81	59	(55)
Dec.	129	94	276	93	147	(1)

Note: L'Anse au Clair based on 14.1% of 1983 L'Anse au Loup total loads and growth rate of 4% p.a. for peak and energy.

Hydro generation based on average water year, 192 kW installation, and no pondage.

8.4 Mini-Hydro Operation

The project (whether 192 kW of 314 kW) will not operate at 100% capacity factor at any time, because no storage, or even pondage is assumed to be available. Thus output will be relatively constant on a daily basis and governed only by the river flow, except when this exceeds the maximum plant discharge.

Under normal operation therefore, the hydro plant will be base loaded in the Anse au Loup system with existing diesel plant providing the balance of the required generation.

During the peak runoff months, (of May and June approximately), the project will generate at full output 24 hours per day. This energy can be fully utilized in the L'Anse au Loup system. In extreme low flow periods, and assuming no upstream storage is provided, the plant will have to be shut down if the river flow drops below about 10% of the rated turbine discharge. Using the derived daily flow duration curve this situation could occur for 8% of the time, (usually in February and/or March) with the 314 kW installation. However, the smaller 192 kW unit could operate over the full range of available flows. The unusuable energy for the 314 kW scheme has not been excluded from the calculation of generation costs.

The L'Anse au Clair hydro station would be used to reduce existing and future diesel generation, and therefore may be evaluated on the basis of fuel replacement. The hydro project will have no guaranteed or firm capacity capability, unless upstream storage is provided. Consequently it has no capacity value, in terms of reducing future diesel installation requirements.

It is relevant to note that the average output of the 314 kW hydro project corresponds to about 22% of the 1983 L'Anse au Loup (net) generation requirements. The project's output would be about 160% of the present energy requirements for the community of L'Anse au Clair. The hydro average output would continue to be greater than the community's forecast demands until about the year 1995. By comparison, the output of the smaller 192 kW project would be fully utilized in L'Anse au Clair by about 1990.

8.5 Storage

The project, as described previously, has been conceived as a run-of-the-river development with no pondage for daily peaking or storage to augment winter generation.

A storage reservoir could provide several benefits:

- ability to use the full capacity of the plant at any time

- increase in winter generation, and hence average energy production.

An analysis was carried out to define these benefits as a function of live storage volume, hence dam budget and capital cost, based on a storage dam at Deep Pond (Section 5.6).

Firm Energy

Storage benefits, in terms of increase winter flows, were calculated using flows for the period December, 1972, to April, 1973, which is the direct period in the 1967 to 1975

derived streamflow record. These flows, at the intake/weir location, were estimated to be:

Month	Flow m^3/s
December	0.3000
January	0.0802
February	0.0559
March	0.0520
April	0.0538

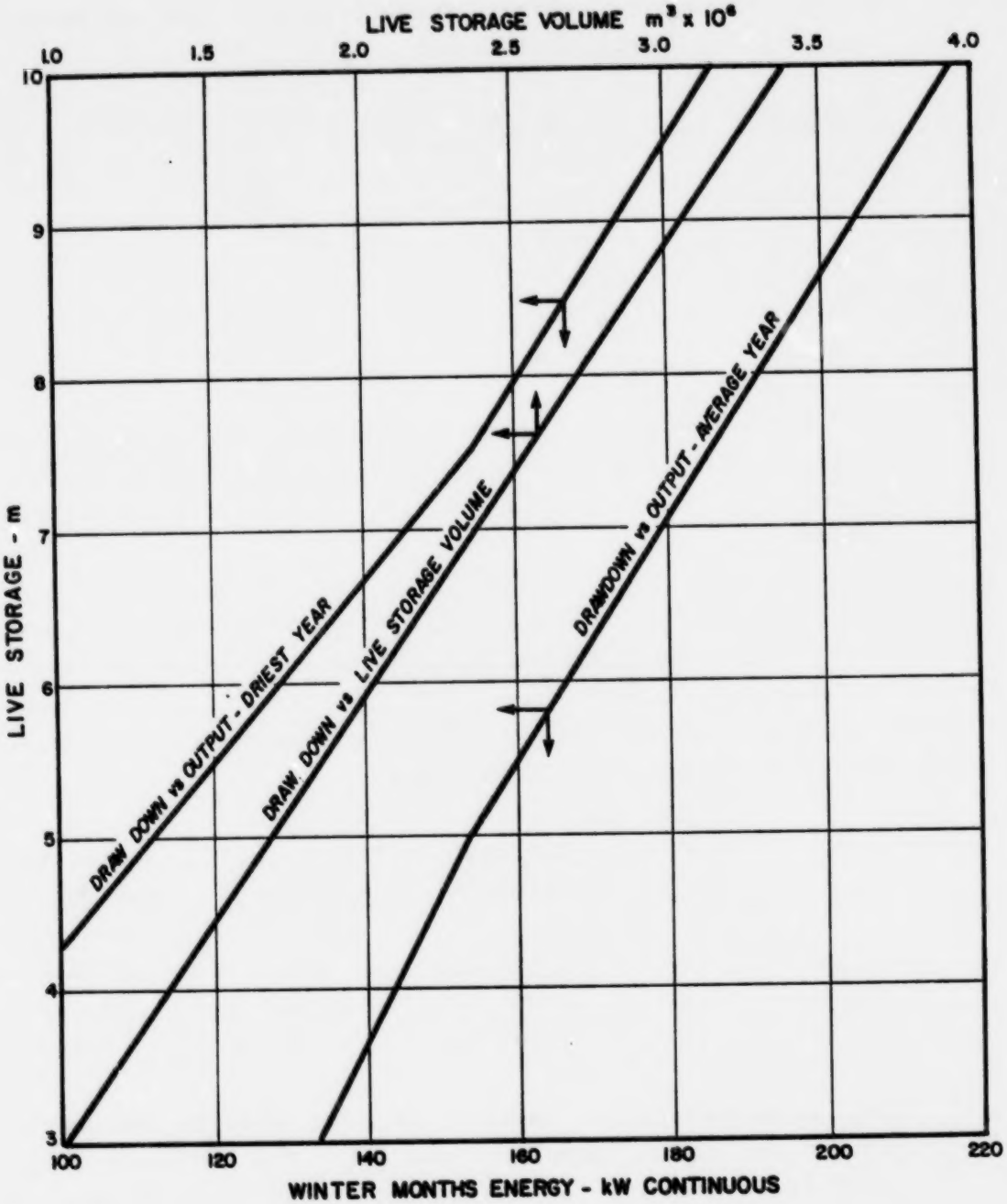
For target regulated plant flows up to 0.3 m^3/s, the critical period is January to April, inclusive. For higher flows, the test period should include the preceeding December.

The relationship between live storage requirement for make up flow and continuous output, based on the 314 kW scheme, is shown in Figure 8.2. For the range of dam heights examined, the resulting winter generation in the driest period on record would have been:

FSL	Storage m	Storage Volume m^3	Firm output Con. kW	Jan-April MWh/Month
121.0	6	2 025 000	129	94.2
123.0	8	2 700 000	161	117.5
125.0	10	3 375 000	194	141.6

The requirements to refill the live storage during the summer wet months have been checked. The available runoff into the reservoir is sufficient, in an average year, to refill the reservoir in each case, while allowing power generation in excess of the firm output to be maintained.

FIGURE 8.2



RESERVOIR STORAGE
VS
WINTER GENERATION

The increase in firm energy has no direct effect on the ecomonics of hydro power generation as long as the existing diesel plant can supply the required demand.

Average Energy

The average energy capability of the project will be enhanced by the availability of storage as spillage can be reduced. Similarly to the case for firm energy, winter generation can be increased. The available increase in annual generation, which occurs during the winter months, as a function of live storage volume is as follows:

FSL	Storage m	Increase in Energy - MWh
121.0	6	284
123.0	8	379
125.0	10	470

This increase in energy has a direct value as it would be used to displace diesel generation.

Firm Capacity

The availability of storage means that flows can be increased at any time to meet daily peak load requirements. Assuming an extreme scenario whereby the plant would operate at full output only for a limited numbers of hours perday, the daily storage release requirements, which would be compensated for (or storage replaced) during off load hours, would be less than 34 000 m^3. This is equivalent to a daily drawdown and refill cycle of 0.1 m.

Thus, the construction of a storage reservoir would mean

that the full installation could be valued in terms of firm capacity i.e., at the cost of new diesel plant.

Storage Cost and Benefits

A preliminary estimate of the total cost of the reservoir (Figure 5.4) to provide 6 m of live storage, including all overheads, is $740 000, while the corresponding cost for 10 m of storage is $1 230 000.

Benefits will accrue from increased average energy, valued at replacement diesel, i.e., 16.5 cents/kWH, and increased firm capacity that may be valued at about $800/kW.

It is assumed that new capacity is required by 1987, which may be the case, the benefits and costs from storage may be compared in terms of present worths at an interest rate of 10%.

	FSL 125 (10 m)	FSL 121 (6 m)
Benefits:		
Average energy	747 600	451 730
Capacity	251 200	251 200
	998 800	702 930
Capital Cost	1 230 000	740 000

This shows that while a storage reservoir would result in useful benefits, the economics of adding the facility are very marginal. This comparison does, however, suggest that if this project is developed further, storage options should be re-examined.

9.0 ENVIRONMENT AND SOCIOECONOMIC ASPECTS

9.1 Land Use

The project involves the construction of a concrete power house, 1 km long penstock, intake dam/weir and short transmission line from the powerhouse to the town. In order to construct and maintain these facilities, a series of access roads will be constructed. Most of the road construction will be raised backfill construction over existing ground. This will eliminate the need for stripping and thus a minimum amount of disturbance to the ecology.

The flooding at the intake dam will be approximately 0.4 Ha at full supply level (EL 72.0). This should have negligible effect upon wildlife and waterfowl habitat. The run-of-the-river scheme will have no effect upon recreational activities in the area.

The construction of the storage dam at Deep Pond will require the flooding of approximately 8-10 Ha if the pond is raised 6 m above its present level (areas calculated are based on limited mapping). This should have minimal effect upon wildlife and waterfowl habitat.

Except for the problems associated with fish, which are discussed in Section 9.2, the proposed development does not appear to pose any serious environmental problems.

9.2 Fisheries

There is no sampling data of fish species or verification of fish migration for Eastern Brook. Therefore, any information available is based on personal observations and

assumptions. During the field trip to L'Anse au Clair, local residents were questioned about the presence of fish in the brook. Based on the response of these individuals, it appeared that only brook trout were known to frequent the brook. However, it is the opinion of Fisheries and Oceans personnel that Eastern Brook contains a run of sea trout as well as salmon parr and smolt. Based on the instructions contained in their telex of October 22, 1984, the usable flows for turbine operation were calculated. (Correspondence with Fisheries and Oceans is included in Appendix 6)

These reduced flows have considerable impact on the output of the system and before the project proceeds, more detailed investigation should be carried out to determine if it is necessary to release 25% of total stream flow at all times or could it be limited to migration periods only.

9.3 Community Impacts

It is not anticipated that the development will have any major impact upon the community, at least not from a social aspect. The construction phase of the project will require some 150 to 190 man months of employment depending on the extent of development. This is referred to in Section 6.3. It should be feasible to recruit the bulk of the labour force from the immediate area. The usual spin-offs such as hotel accommodations, purchase of fuels for construction and short term increase in local business will also result.

In the event that the community council or some other association directly connected with the town, were able to develop and operate the project, then the real economic benefits would result from the sale of energy produced. The community council may have difficulty in administrating

such a project because of its mandate under the Municipalities Act. This is further discussed in Section 10.6. Other organizations and/or private concerns may be in a better position to administer the project.

9.4 Water Rights

The subject of water rights, pertaining to hydro development, are not well defined by the Government of Newfoundland and Labrador at the present time.

Requirements for obtaining permission to proceed with hydro electric development previously came under Chapter 71 of "An Act Respecting Crown Lands, Timber and Water Power of the Revised Statutes of Newfoundland, 1970". The Department of Forest Resources and Lands, responsible for administrating this act, have been notified to refer all applications for water rights to the Department of Environment.

The Department of Environment are now in the process of drafting a Water Resources Act. Presently, a developer wishing to develop hydro electric power, must make application to this Department. Engineering plans and specifications of the intended development must also be submitted, along with the application. These plans and specifications must be approved by the Minister before development can proceed. As part of the approval process, Newfoundland and Labrador Hydro will be informed of the development since they have the first option to water rights in the province. Should they not be interested or have no objection to the development, then approval will be granted provided all other requirements are met.

10.0 PROJECT EVALUATION

The evaluation of a hydroelectric project may be presented in a number of ways, including:

- Comparison of unit generation costs in constant prices
- Comparison of total system generation costs on a present worth basis in constant or current prices
- Comparisons of payback periods, with or without escalation.

Conventionally, analyses carried out by, or for, Canadian Federal and Provincial agencies are based on comparisons made in constant prices. In some cases, a real or differential escalation rate may be applied to one component, such as fuel. The application of analyses, using current prices, is usually limited to inputs for tariff or financing studies.

In the case of the L'Anse au Clair project, and assuming no storage, the project is evaluated in terms of the use of new hydro energy to replace generation from diesel units, i.e., at the variable cost of diesel generation.

Based on these considerations, the basic evaluation of the hydro alternatives is based on direct comparison of hydro total and diesel variable generation costs, excluding escalation. This provided a direct measure of the viability of the hydro project as a function of interest rate. Providing that capacity benefits are not to be excluded, the results would be identical to those obtained from comparison of present worths or net present values.

In this context, it is important to recognize the effect of including escalation allowances. Thus, a decision discount or interest rate of 13%, with escalation averaging 4%, would be equivalent to a decision rate of about 9%, if escalation is excluded.

It is recognized that the payback period is a useful measure of the viability of a project. This analysis has also been included.

10.1 Cost of Diesel Generation

The evaluation of the proposed hydroelectric project is based on the value of diesel generation that may be displaced by the energy available from the hydro project.

The variable cost of diesel generation, i.e., excluding any capital related charges for equipment, is made up of

- fuel costs
- lubricating oil costs
- variable operation and maintenance costs.

Diesel Fuel

The power commission (Newfoundland and Labrador Hydro) have provided actual fuel costs for the l'Anse au Loup station for recent years (Appendix 6). These show diesel fuel costs as follows:

Year	Fuel Consumption ℓ	Fuel Cost $	Unit Cost $/ℓ
1981	1 922 000	526 800	0.274
1982	2 053 000	653 700	0.318
1983	2 156 000	738 200	0.342

While historically, the unit cost of fuel has been increasing steadily with direct fuel price changes, the overall generation efficiency (measured as net kWh per litre of fuel) has been decreasing.

Year	Efficiency kWh/ℓ
1980	3.01
1981	2.98
1982	2.94
1983	2.95

These two parameters account for most of the variable diesel generation cost. For the purpose of this study the diesel generation fuel cost has been based on

Fuel cost	$/ℓ	0.350
Efficiency	kWh/ℓ	2.95
Unit Fuel Cost	$/kWh	0.119
Lubricating Oil	$/kWh	0.006

The use of lubricating oil is primarily a function of the age of the generating equipment. Reported useage for the L'Anse Au Loup diesel station varies from 2.5% of diesel fuel (on a cost basis) in 1981 to 3.8% in 1983.

A conventionally used value is to add 5% to the diesel fuel costs to cover lube oil usage for relatively new small units. This allocation has been used for the current analyses.

Operation and Maintenance

Operation and maintenance costs may be allocated as being

fixed and variable. Reported costs for the l'Anse au Loup station vary between 3.5 and 4.1 ¢/kWh (net) for the years 1981 to 1983. These costs will tend to increase with age of the generating units. For the purpose of these studies a variable or energy related O & M cost has been taken as 4 ¢/kWh.

Total Variable Costs

The total variable diesel generation cost is therefore assumed as

	$/kWh
Fuel Cost	0.119
Lube Cost	0.006
O & M	0.040
	0.165

10.2 Hydroelectric Generation Costs

The calculation of hydroelectric generation costs is based on fixed charges as follows.

Capital cost, based on 1985 prices;

Operation and maintenance, which, for these analyses, was assumed to be the same for all project arrangements. A fixed amount cost of $40 000 was used which includes an allowance for overhead or general expenses.

Insurance, (or an allowance in lieu of). A fixed annual amount was set at 0.1% of the capital cost of the project.

Interim replacement, a fixed annual amount was set at 0.22% of the capital cost of the project. This accounts for replacement of major equipment items with service lives shorter than the 35 years assumed for the project.

Interest Rates

There is a wide range in the interest or discount rates presently being used by lending agencies on which a project's viability is based. For comparisons made in constant dollars, i.e., excluding escalation, most agencies use rates near 10%. For this study, unit generation costs have been calculated for a range of interest rates, from 8% to 14%.

Service Lives and Depreciation

Depreciation allowances are calculated on the basis of sinking fund payments to replace the capital cost of the project by the end of its useful service life. The service life assumed for a project is a function of the size and type of generation, ranging from about 15 years for diesel to more than 50 years for major hydro plants.

The project life of hydro plants is theoretically measured by the life of the dam and major civil structures, since electrical and mechanical equipment can be replaced on an interim basis.

It is noted that for accounting purposes all types of generating stations are written off at a shorter life than they may be expected to last for.

For this study, and in view of the small size of the project, a service life of 35 years has been assumed for the L'Anse au Clair development.

Unit Hydroelectric Generation Costs

The calculation of unit generation costs is therefore based on the following annual costs.

Capital related charges:

- interest
- depreciation
- interim replacement
- insurance.

Operating charges:

- operation and maintenance
- general administration or overhead.

The analysis are based on:

Scheme	314 kW	192 kW
Capital Cost - Hydro	$1 239 600	$1 094 900
Average Annual Energy	1 470 000	1 159 000
Capital Cost-Transmission	240 000	80 000

The calculation of unit costs is shown in Tables 10.1 and 10.2, and are summarized below. A graphical presentation is given in Figure 10.1. In order to show the sensitivity of the costs to the estimated capital cost, unit costs were also calculated with the capital cost for the hydro plant and transmission increased by 10%.

Unit Hydro Generation Costs - ¢/kWh
(including Transmission)

Interest Rate	314 kW scheme		192 kW scheme	
	Base Capital Cost	Capital Cost +10%	Base Capital Cost	Capital Cost + 10%
8	12.28	13.24	12.09	12.95
10	14.20	15.35	13.83	14.86
12	16.20	17.53	15.63	16.85
14	18.26	20.03	17.48	18.89

TABLE 10.1

UNIT HYDROELECTRIC GENERATION COSTS - 314 kW SCHEME

Interest Rate	8%	10%	12%	14%
A. Hydro Project				
Annual Costs: $,000				
U.A.P.	114.94	138.92	163.84	189.43
O & M + Admin.	40.00	40.00	40.00	40.00
Insurance	1.34	1.34	1.34	1.34
Interim Replacement	2.95	2.95	2.95	2.95
Total	159.23	183.21	208.13	233.72
B. Transmission				
Annual Costs $,000				
U.A.P.	20.54	24.59	29.35	33.94
Other Costs	0.72	0.72	0.72	0.72
Total	21.31	25.61	30.07	34.66
Unit transmission cost ¢/kWh	1.45	1.74	2.04	2.36
Unit cost delivered energy ¢/kWh	12.28	14.20	16.20	18.26

Where:

Capital Cost Hydro	$ 1 339 640
Capital Cost Transmission	240 000
Average Energy after losses	1 470 000

TABLE 10.2

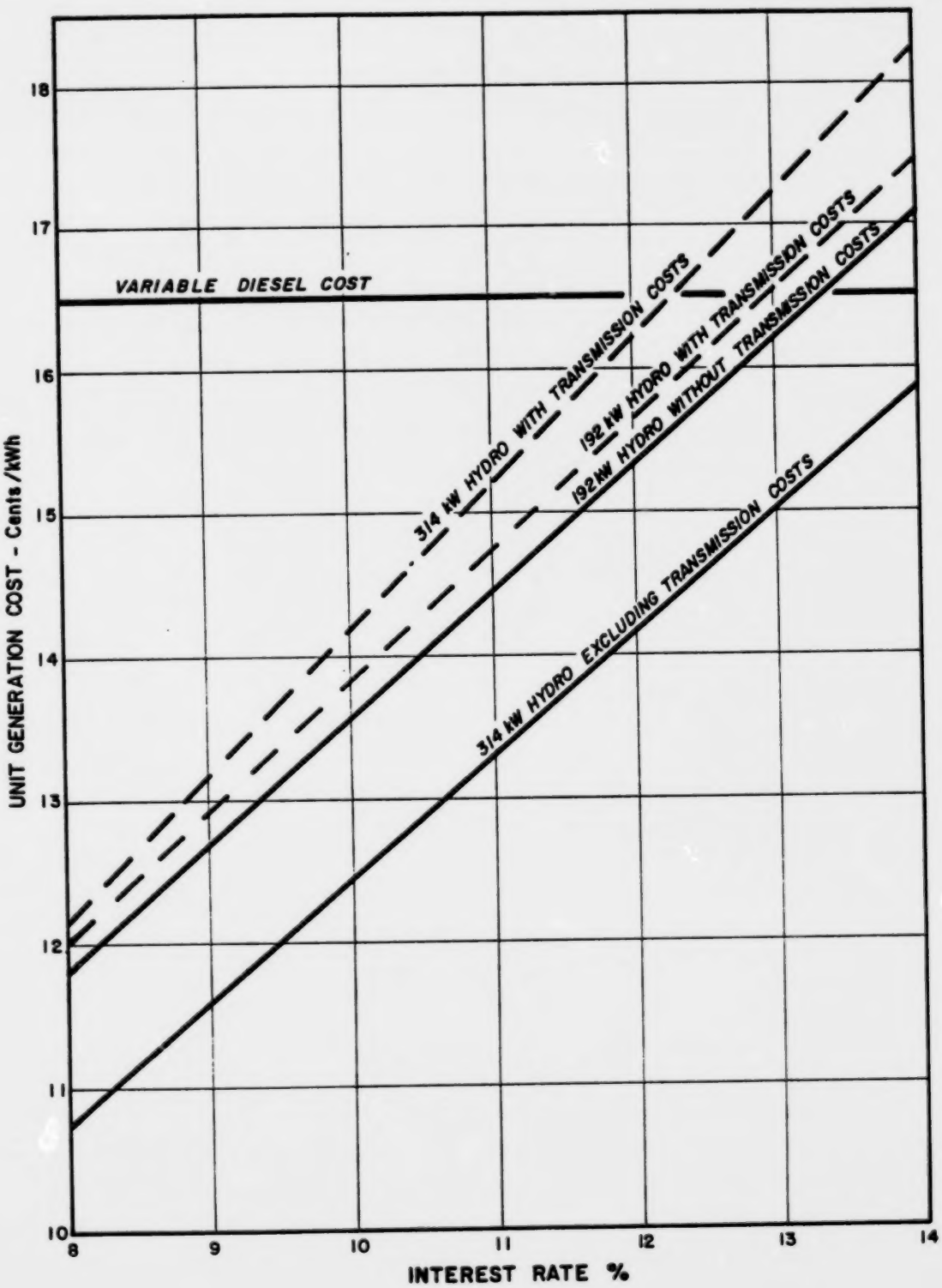
UNIT HYDROELECTRIC GENERATION COSTS - 192 kW SCHEME

Interest Rate	8%	10%	12%	14%
A. Hydro Project				
Annual Costs: $,000				
U.A.P.	93.94	113.54	133.91	154.82
O & M + Admin.	40.00	40.00	40.00	40.00
Insurance	1.09	1.09	1.09	1.09
Interim Replacement	2.41	2.41	2.41	2.41
Total	137.44	157.04	177.41	198.32
B. Transmission				
Annual Costs $,000				
U.A.P.	2.57	3.11	3.67	4.24
Other Costs	0.09	0.09	0.09	0.09
Total	2.66	3.20	3.76	4.33
Unit transmission cost ¢/kWh	0.23	0.28	0.32	0.37
Unit cost delivered energy ¢/kWh	12.09	13.83	15.63	17.48

Where:

Capital Cost Hydro	$ 1 094 920
Capital Cost Transmission	30 000
Average Energy after losses	1 159 000 kWh

FIGURE 10.1



UNIT GENERATION COSTS

10.3 Project Evaluation Results

For this study the economic viability of the project is shown in terms of comparison of unit generation costs for hydro and alternative diesel. Annual net benefits are also shown.

This is an adequate procedure in this case as the reference run-of-river scheme will only provide energy to reduce existing diesel generation and thus implementation of the hydro project is assumed to not affect future capital requirements for later diesel units.

The comparison is therefore made between average hydro generation costs that are partly a function of assumed interest rate (Section 10.2), and the variable cost of diesel generation (Section 10.1).

Comparison of the hydro generation costs listed above, and in Tables 10.1 and 10.2, with the variable or displacement values of diesel generation which is 16.5 ¢/kWh yields the corresponding breakeven interest rates of,

	BREAKEVEN INTEREST RATES	
	314 kW	192 kW
Hydro plant only	14.7%	13.3%
Hydro plus transmission	12.3%	12.9%
Hydro plus transmission Costs increased by 10%	11.1%	11.7%

The above values show that if transmission costs are excluded, both the 314 kW and 192 kW schemes are quite attractive, noting that these comparisons exclude

escalation. With transmission costs added, both projects are still viable by accepted standards, however, the reduced scheme is more attractive because of its low transmission capital cost.

The annual net benefits for each project including transmission costs, based on 1985 prices and a 10% interest rate, would be:

	314 kW	192 kW
Annual Benefits	$242 550	$ 191 235
Annual Costs	208 820	160 240
Net Benefits	33 730	30 995

Life-Cycle Evaluation and Payback Periods

An alternative approach to assessing the economic viability of the project is to compare the present worths of the benefit and cost streams, over the life of the project, to determine the range of discount rates for which the project is viable. Also a useful result from this type of analysis is the payback period, i.e., the time in the future when the accumulated benefits from the project will exceed the project costs, on a present worth basis.

This analysis was carried out for the 192 kW scheme, including transmission. Results were obtained with and without escalation of costs and benefits. The assumed parameters were as follows:

Project Scheme	192 kW
Capital Cost with Tranmission	$1 124 920
Average Energy After Losses	1 159 000 KWH p.a.
On Power Date	1987
Service Life	35 years
Value of Energy	16.5 cents/KWH

For the analyses with escalation, the values suggested by Newfoundland and Labrador Hydro were used (Table 10.3). They provided separate year by year escalation rates for diesel plant, operation and maintenance, and fuel. For the purpose of this study, their rates for fuel have been used to escalate gross benefits, which are based on diesel fuel replacement only. Their suggested rates for operation and maintenance were used for escalating the hydro plant and transmission capital costs and the other annual costs (O & M, interim replacement, and insurance).

The derived present worths of the cost and benefit streams are as follows:

Present Worths of Costs and Benefits $,000

NO ESCALATION

Discount Rate	10%	13%	15%
P.W. Benefits	1524.2	1136.0	956.8
P.W. Costs	1192.6	1038.6	957.8
Net Benefits	331.6	97.4	-1.0

WITH ESCALATION

Discount Rate	18%	20%	24%
P.W. Benefits	1225.8	1034.2	768.7
P.W. Costs	1041.5	962.3	836.2
Net Benefits	184.3	71.9	-67.5

TABLE 10.3

Escalation Rates
(%)

Year	O&M	Diesel Fuel
1985	4.11	5.22
1986	4.99	8.99
1987	3.96	3.46
1988	4.15	4.33
1989	4.00	4.70
1990	4.73	5.16
1991	4.23	4.05
1992	4.11	4.43
1993	4.63	4.90
1994	5.49	5.75
1995	5.70	5.54
1996	5.36	5.45
1997	5.19	5.36
1998	4.84	5.02
1999	4.94	5.06
2000-2015	5.05	5.19

1. Source N&LH February, 1985
2. Escalation applied up to 2021
3. O&M rates used for all capital and operating costs

The above results show that based on constant prices, i.e., without escalation, the 192 kW scheme is viable up to 14.9%. If escalation is included, the breakeven discount rate increases to about 21.8%.

As noted previously, the criteria for selecting a decision discount rate should be different for analyses with and without escalation, with the rates differing by approximately the average escalation rate.

The results without escalation may be compared with those obtained by direct comparison of unit generation costs. That analysis provided a breakeven interest rate of 12.9%. The results obtained using discounted costs and benefits show a higher breakeven rate of 14.9% because all values are discounted to 1985, and this has a greater effect (reduction) on costs than on benefits. This analysis also provides a more meaningful result.

The payback period was obtained from direct comparison of accumulated present worths of costs and benefits, and for discount rates of 10% and 13%, with and without escalation.

Payback Years

Discount Rate	10%	13%
Without Escalation	1999	2004
With Escalation	1995	1996

It should be noted that adding escalation has a much greater effect on benefits than on costs. The major component of the cost stream is the lump sum amount for the project capital cost, in 1987. Whereas, the annual value of replacement diesel generation increases every year up to the end of the project life cycle in the year 2021.

10.4 Project Evaluation with Storage Reservoir

The benefits and costs that would result from the construction of a storage reservoir have been described in Section 8.5. The analyses showed that storage development is likely to be marginal in terms of project viability. Also, the addition of storage (6 m) would increase the capital cost for the 314 kW scheme by about 50% and change the whole project concept.

As a result, for the purpose of this study, the storage option has not been considered further and thus, its costs and benefits have not been included in the evaluation of the project.

The comparison of benefits and costs do indicate that further studies on storage would be warranted if the overall project is to be studied in more detail.

These studies would first require a decision on whether the hydro project is to supply local loads or the L'Anse au Loup system. The more detailed investigation of the storage dam would require:

- field investigations (topography, foundation, and materials)
- storage operation simulation
- overall project evaluation based on a generation plan for the L'Anse au Loup system.

10.5 Inpact of Fisheries Requirements

The analyses have assumed that at least 25% of the natural

runoff at any time is not used for power generation, in order to maintain flows in the stream channel for fisheries.

This criterion affects the selection of the optimum installation, the available energy, and the economic viability of the project.

During the first stage of the study, the flow release criterion had not been identified. The optimization study for the basic project - for supply to the L'Anse au Loup system, resulted in the selection of a 390 kW installation as compared with the revised capacity of 314 kW.

The available energy from the 314 kW project, after allowing for the fisheries flow release, is 1470 MWh p.a. If all flows up to the plant discharge capacity were used, the available average energy would increase to 1724 MWh p.a. or by 17.3%, and unit generation costs would decrease by the same percentage.

For the 314 kW scheme with transmission costs included, the net annual benefits (at 10% interest) and breakeven interest rate would increase as follows:

	With 25% Flow Release	No Flow Release
Net Annual Benefit	$33 730	$76 180
Breakeven Interest Rate	12.3%	15.3%

This comparison provides a measure of the significance of the flow release criterion. Thus, in any further studies on the project, this criterion should be re-examined in more detail and either confirmed or modified.

10.6 Implementation Plan

In order to proceed with one of the schemes outlined in this study, then the following steps will be required:

1. Decide on who the developer will be,

2. Arrange financing,

3. Carry out further field surve reappraise fisheries requirements then pro detailed engineering design and specificati

4. Call tenders for the various project contracts.

5. Proceed with construction.

The decision as to who will be the developer is beyond the scope of this study. The Department of Municipal Affairs have indicated that a town council or community council does not have a mandate to get involved in hydro development. Based on a conversation with an official of the Department of Rural Agriculture and Rural Development, it appears that Rural Development Associations are in a similar situation, as that of Town Councils. It would appear that other than some private developer, the most logical candidate would be Newfoundland and Labrador Hydro.

Possible funding sources for project development were investigated from both government and private sources. The following is a list of departments and companies contacted along with comments regarding the possibility of their involvement.

Federal

Department of Regional Industrial Expansion

The Industrial Regional Development Program (IRDP) is intended to assist manufacturers establish in the province. It specifically excludes the generation of electricity unless it is produced as an integral part of the processing facilities. An example would be if they wanted to expand the fish plant in the town and the present distribution system was not able to supply suitable power, i.e., 1Ø vs 3Ø, then if the new turbine/generator were installed to exclusively satisfy this need, then maybe it would qualify for funding.

Employment and Immigration Canada

This department has a program entitled Local Employment and Assistance Program (LEAP) which is intended to assist in further economic development of a community and the creation of long term employment. The emphasis is on job creation. It was felt that the proposed mini-hydro development was outside of the scope of this program.

Provincial

Department of Development

There are no programs available through this department under which this type of project would qualify.

Department of Rural Agriculture and Northern Development

This department makes funds available through the various rural development associations for resource based projects

which have prospects for long term job creation. It was felt that this was a unique project for them to get involved in. They would have difficulty in justifying funding for such a project, under their present mandate.

Department of Mines and Energy

At present, there is no program or specific funds available to assist in the development of such projects. However, projects will be reviewed on an individual basis and the possibility of funding was not ruled out completely.

Private

Newfoundland Light and Power

They are interested in small scale hydro development, but felt that this particular project was not within their area of operation and hence, would not be willing to participate.

Staphenhorst Turbines

This company appears to be willing to enter into further discussions on funding, provided their turbines and equipment were used in the project. It was indicated that they would be willing to finance such a project. Payback would be based on the amount of electricity produced, by the unit, at a rate equal to the cost of diesel generation in the area. The developer could buy back whenever he wished to do so.

These investigations indicate that it may be possible to secure some funding from the Department of Mines and Energy as well as Staphenhorst Turbines providing terms of

agreement with regards to equipment purchase can be worked out. Other sources of funding not included in our investigation are Newfoundland and Labrador Hydro, and Energy, Mines and Resources Canada under Phase II of the Remote Community Demonstration Program.

Before proceeding with engineering plans and specifications, further field surveys and investigations will be necessary. Geotechnical surveys and investigations concerning structure foundations and aggregate sources should be carried out, and the penstock route will have to be finalized. More detailed topographical surveys and profiles will also be necessary.

Reappraisal of fishery requirements will also be necessary to determine if 25% of the stream flow will be necessary, at times when fish are not migrating. Should it be decided to intergrate storage into the scheme then a more detailed assessment of storage facilities will be necessary.

Once the field surveys are completed, then detailed engineering design and specification preparation can commence. The calling of tenders and schedule of construction can be carried out in a manner similar to that described in Section 6 of this study.

10.7 Purchase of Power

If Newfoundland and Labrador Hydro develop and operate the system, then the purchase of electrical energy produced will not be a concern. However, if someone other than Newfoundland and Labrador Hydro should develop the system, then the arrangement for the purchase of power will be of prime concern.

Presently, there are few, if any, guidelines in effect in the province pertaining to the purchase of electrical energy from small hydro developments operated by private developers. Hence, before commencing to develop any small scale hydro sites, a private developer will have to be assured that an agreement to purchase energy is in place with the utility companies.

It is beyond the scope of this study to draft an agreement for the purchase of energy. However, in the province of Ontario, such an agreement is in place to compensate the small developer for energy produced. A copy of this agreement is included in Appendix 7. This could be used as a guide to draft an agreement for the purchase of energy from private developers in the province.

REFERENCES

REFERENCES

1. Remote Community Demonstration Program - Newfoundland Regional Overview Study, Brador Resource Management Ltd. and BFL Consultants for Energy, Mines and Resources.

2. Methodology for the Design and Costing of Small Hydro Plants, Shawinigan Consultants Inc., CEA Report, 1983.

3. Small and Micro Hydroelectric Power Plants - Technology and Feasibility, Energy Technical Review No. 60, Noyes Data Corporation, USA, 1980.

4. Study of Hydro-Electric Potential in Southern Labrador, SNC and Nolan, White & Associates, Newfoundland and Labrador Hydro, 1979.

5. Study of Small Scale Hydro for Newfoundland and Labrador, Shawmont Newfoundland Limited, Newfoundland and Labrador Hydro, 1979.

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10. Estimating Flow Duration Curves in Tropical Equatorial Regions, S.I. Ransahoye, Water and Dam Construction, December, 1982.

11. Meilleur Ajustement Statistic aux Débits Journaliers de Crue et D'etiage des Rivières du Québec, V. D. Hoang, M.R.N., Quebec, Service de L'Hydrométrie, 1978.

12. Canadian Climate Normals, 1951-1980, Environment Canada, 1982.

APPENDIX 1

Terms of Reference

THIS WORK STATEMENT IS ANNEX A TO THE AGREEMENT BETWEEN CANADA AND COMMUNITY COUNCIL OF L'ANSE AU CLAIR MADE 10 AUGUST 1984.

Objective

The objective of the study is to determine the technical and economic feasibility of developing a small scale hydro site in the community of L'Anse au Clair.

Work Statement

1. A steering committee will be established to offer comments and direction to the consultant pertaining to the study. The committee will consist of one representative of each of the following:
   - Newfoundland and Labrador Hydro
   - Energy, Mines and Resources
   - The Community of L'Anse au Clair

   The work is to be carried out in four (4) stages with meetings held at the end of each stage.

2. Stage 1 - Identification of Development Sites

   Available maps, data and a hydrology analysis will be used for a potential drainage assessment of the area. Aerial photos will also be studied to get a more accurate feeling for the local terrain. The following activities will give a first stage idea of hydro potential and also location and size of development alternatives.
   - Acquisition of aerial photos
   - Acquisition of required hydrological and meterological data
   - Topographic map study
   - Potential drainage assessment
   - Aerial photo study
   - Preliminary development of alternatives

3. Stage 2 - Ground Survey and Alternative Development

A ground survey of the potential sites will give a more accurate evaluation of the alternatives and the power potential of the area. The survey will consist of but not necessarily be limited to:

- reconnaissance of potential sites
- discharge investigations
- establishment of basic vertical control
- barometer profiling
- materials survey of area
- selection of structure site(s)
- development alternatives and energy assessment

4. Stage 3 - Preliminary Design and Cost-Benefit Analysis

Once a site has been selected and alternative evaluated, the capital cost for construction and operation costs can be evaluated. Head and flow patterns will allow for potential energy generation to be calculated and benefits analyzed.

The purpose of such a project will be to provide an alternative mini-hydro power source to operate in parallel with the existing generation system. The major economic benefit is therefore the value of the fuel displaced by the addition of this alternative supply. Economic benefits of the availability of the additional power to the local industry will also be considered.

The major activities of this section will include:

- preliminary design work for dams, weirs, intake, water passages, power house, turbine and generator
- time and duration water flow patterns
- net or real fuel savings
- final cost-benefit conclusions, based on life-cycle costing.

5. Stage 4 - Final Design Selection

This will involve a final design selection and recommendations for future development. A cost benefit analysis will be carried out and will be based on life cycle costing.

6. In addition to the four (4) stages mentioned, the following items will be addressed and included where appropriate in the four (4) stages of the study:

   - water rights, environmental and socio-economic impacts
   - system costing will include the following
     - electrical transmission to the community
     - distribution system upgrading
     - interconnection to the diesel grid
   - a demand analysis of the community will be conducted taking into account potential energy conservation
   - an implementation plan will be prepared outlining the steps required to implement a project and identifying potential funding sources

7. Reports

   A draft final report shall be submitted to the study management committee for comments. These shall be taken into account, and a final report prepared, containing as a minimum: table of contents, executive summary, introduction, technical and economic discussion, conclusions, recommendations, bibliography or references.

   One original reproducible and ten (10) copies of the final report shall be given to Energy, Mines and Resources Canada.

8. Community Meeting

   If the community wishes, a presentation of the study's findings shall be made to the community.

APPENDIX 2

Community Profile Information for L'Anse au Loup and L'Anse au Clair

		Page
1.	L'Anse au Loup distribution system Pages 124-127 of Remote Community Demonstration Program - Newfoundland Region - Overview Study*	118
2.	L'Anse au Clair community profile Pages 143-151 of Remote Community Demonstration Program - Newfoundland Region - Overview Study*	122
3.	L'Anse au Loup community profile Pages 152-164 of Remote Community Demonstration Program - Newfoundland Region - Overview Study*	131

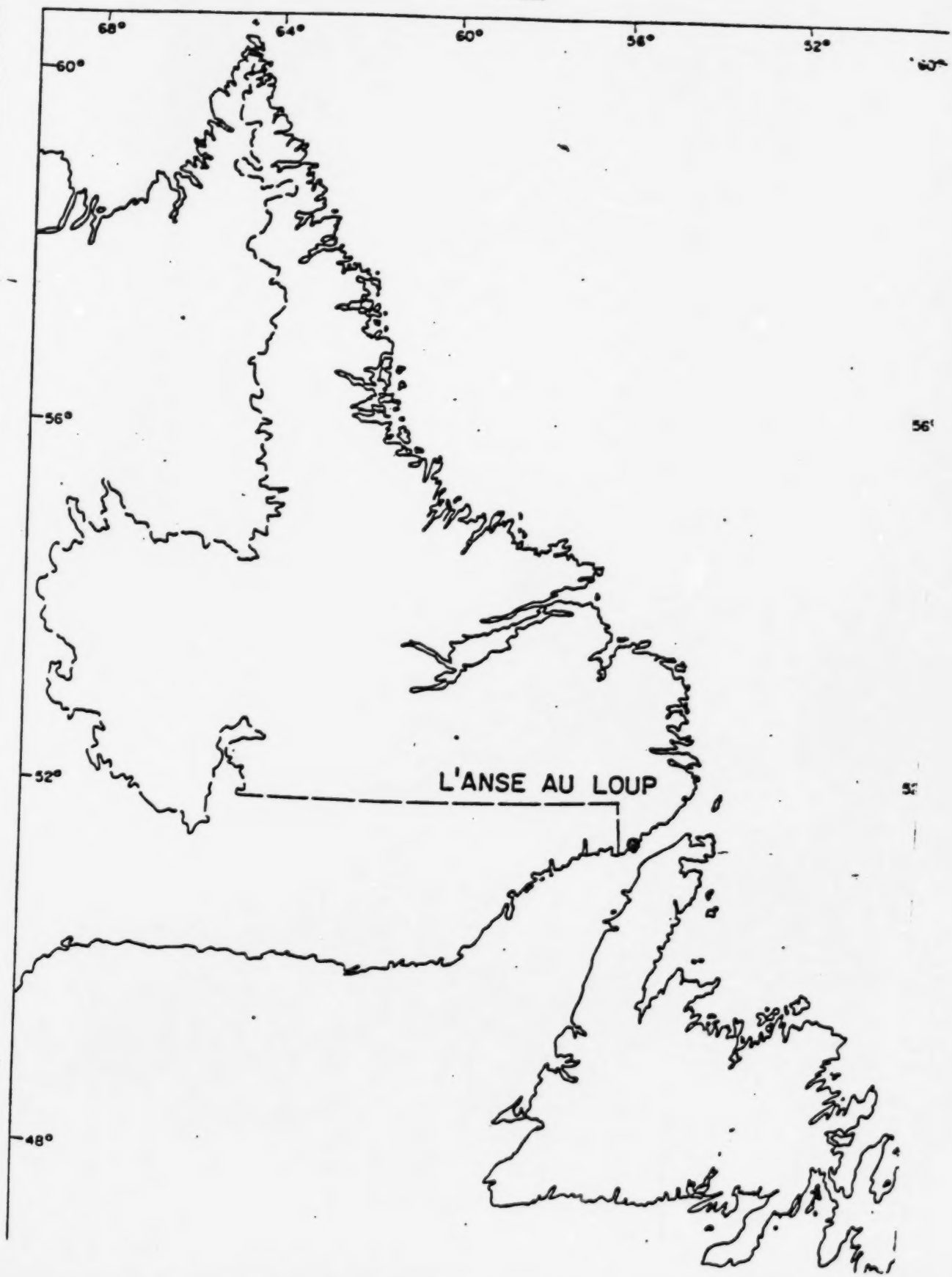
* This report was prepared for the Remote Community Demonstration Program of Energy, Mines and Resources Canada in 1983 by Brador Resource Management Ltd. and BFL Consultants Ltd. of St. John's, Nfld.

4.6 REMOTE COMMUNITY ANALYSIS

Load Center: L'Anse au Loup

Communities Serviced: Capstan Island, English Point, Forteau, Fox Cove, L'Anse Amour, L'Anse au Clair, L'Anse au Diable, L'Anse au Loup, Pinware, Red Bay, West Ste. Modeste

Comments: The L'Anse au Loup diesel generating plant services a total of eleven communities as indicated above. For six of these communities, town planning information is available, and consequently the profiles are reasonably detailed. For the other five communities, the amount of information available is sparse. The information available for each community will be presented separately, beginning with those communities for which detailed data is available.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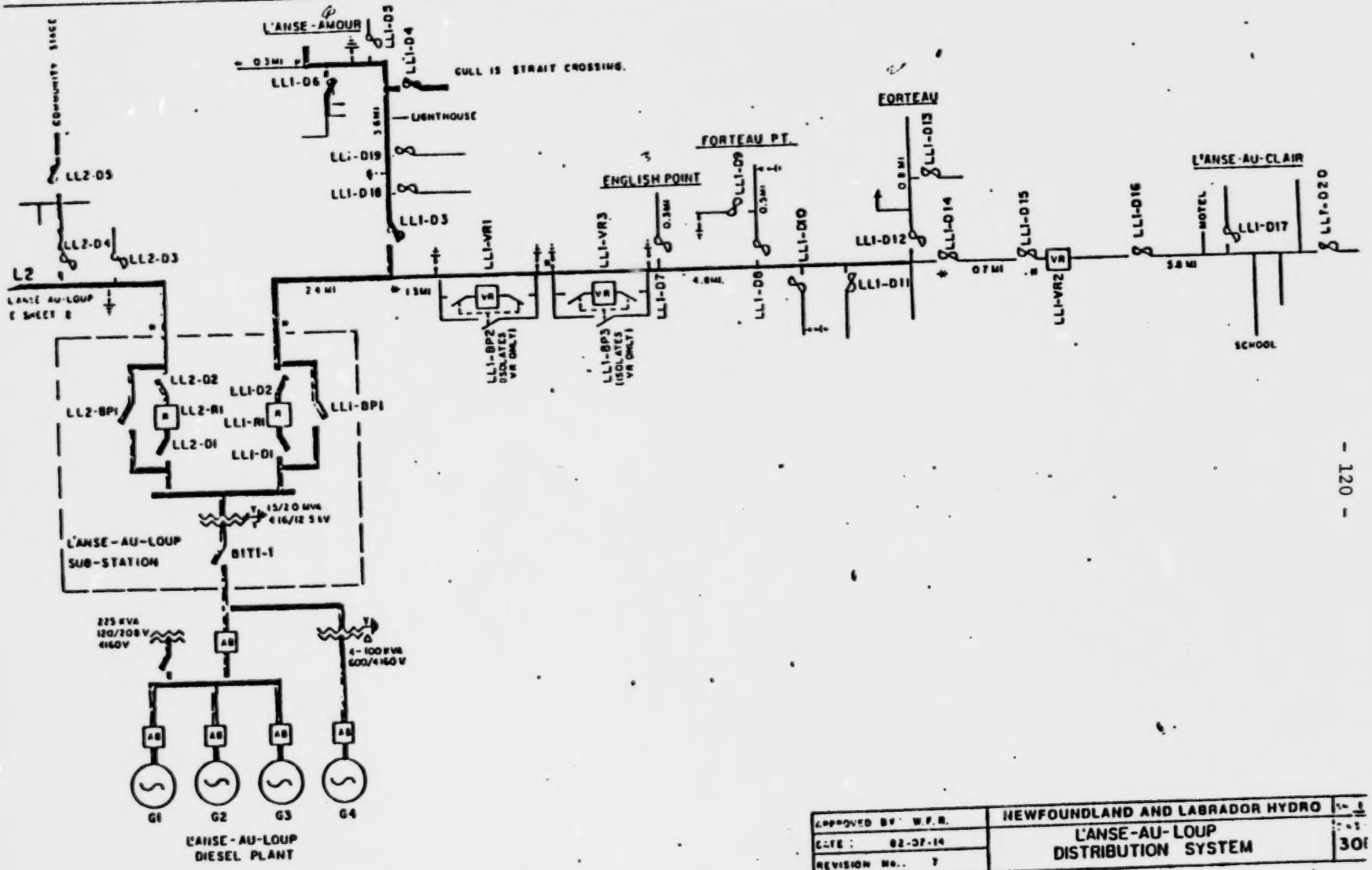
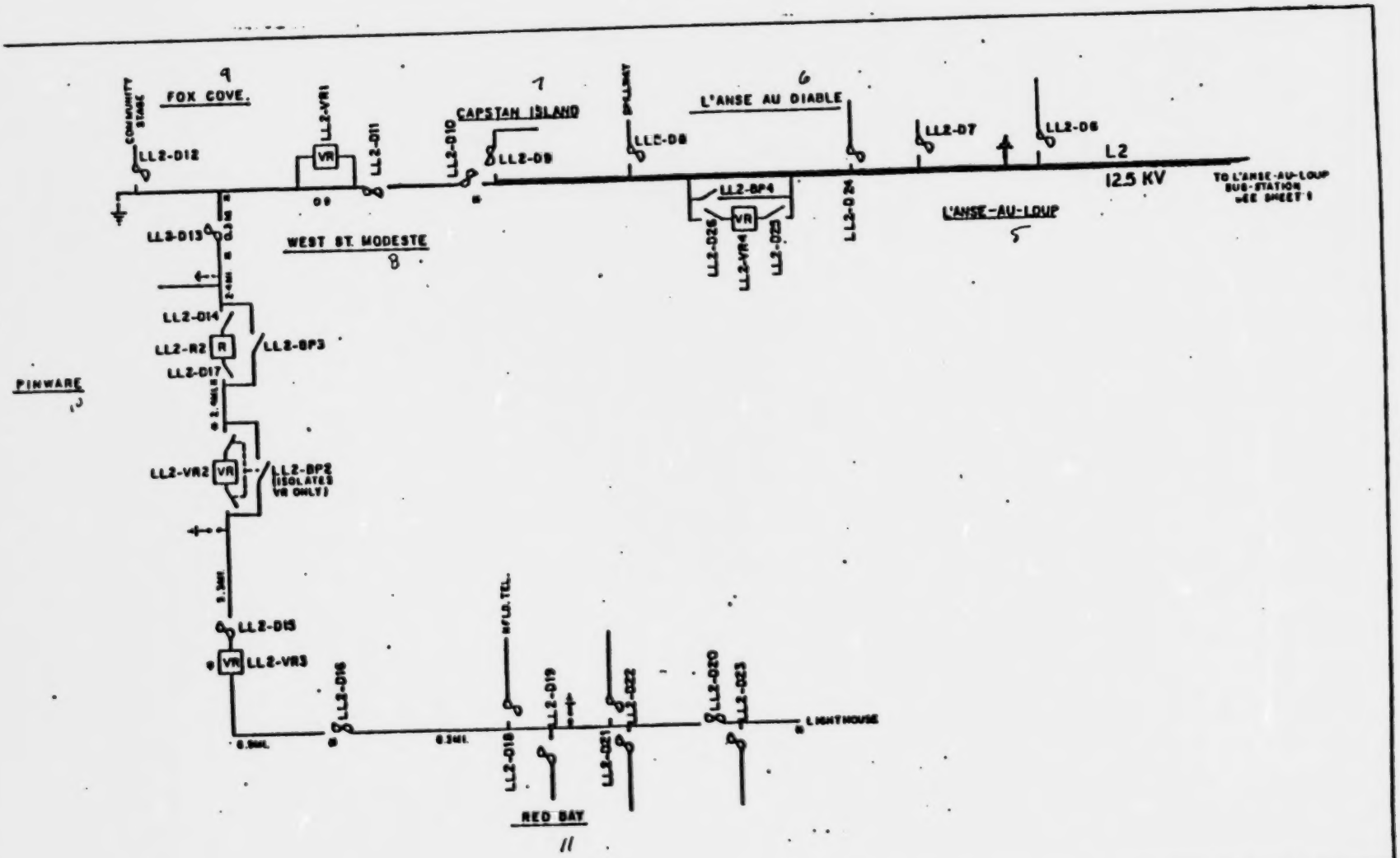
48°
L'ANSE AU LOUP


L'ANSE-AMOUR
LLI-05
LLI-04
LLI-06
CULL IS STRAIT CROSSING.
LIGHTHOUSE
LLI-D19
LLI-D18
LLI-03
LL2-05
LL2-04
LL2-03
L2
LLI-VR1
LLI-VR3
ENGLISH POINT
FORTEAU PT.
LLI-09
LLI-07
LLI-08
LLI-D10
LLI-D11
LLI-D12
FORTEAU
LLI-013
LLI-D14
LLI-D15
LLI-VR2
LLI-D16
L'ANSE-AU-CLAIR
MOTEL
LLI-D17
LLI-020
SCHOOL
LLI-BP2
LLI-BP3
LL2-02
LLI-02
LL2-BPI
LL2-RI
LLI-RI
LLI-BPI
LL2-DI
LLI-DI
L'ANSE-AU-LOUP
SUB-STATION
BITI-1
225 KVA
120/208 V
4160 V
4-1000 KVA
600/4160 V
G1
G2
G3
G4
L'ANSE-AU-LOUP
DIESEL PLANT
APPROVED BY W.F.R.
DATE : 82-07-14
REVISION No.. 7
NEWFOUNDLAND AND LABRADOR HYDRO
L'ANSE-AU-LOUP
DISTRIBUTION SYSTEM



APPROVED BY: W.F.R.	NEWFOUNDLAND AND LABRADOR HYDRO	Sht 2 of 2
DATE: 82-11-17	L'ANSE-AU-LOUPE DISTRIBUTION SYSTEM	Dwg No. 308-2
REVISION No.: 0		

4.6.3 REMOTE COMMUNITY ANALYSIS

Community Profile: L'Anse au Clair, Labrador

Status: Incorporated

Location: Lat: 51° 25' N
Long: 57° 05' W

Sources of Information:

Publications and Articles

Arco Co. Ltd. and Terpstra Engineering Ltd., "L'Anse au Clair Municipal Plan," May 1980.

Them Days Magazine, "Alluring Labrador," October 1980.

Place Name Codes of Newfoundland and Labrador, January 1981.

Selected Characteristics - Newfoundland - 1981 Census of Canada.

Interviews and Correspondence

Newfoundland Statistics Agency, May 1981.

Statistics Canada, May 1983.

Newfoundland and Labrador Hydro/Power Distribution District, May 198

Royal Canadian Mounted Police, June 1983.

Department of Municipal Affairs and Housing, May 1983.

Woodward's Oil Limited, June 1983.

Department of Health, June 1983.

Department of Transportation, June 1983.

Intergovernmental Affairs Secretariat, June 1983.

A. History and Current Status

1. L'Anse au Clair was established by the French in the early 18th century. Englishmen and Newfoundlanders settled there during the first half of the 19th century, shortly after the border dispute in 1825.

L'Anse au Clair is considered the gateway to the Labrador Straits and is the only Straits community with a hotel facility. This probably developed to take advantage of the close proximity to the ferry and air services at Blanc Sablon, Quebec. L'Anse au Clair is therefore serving a regional function and has a head start on the tourism industry.

2. Demographics

1981 Population: 267

Historic Population

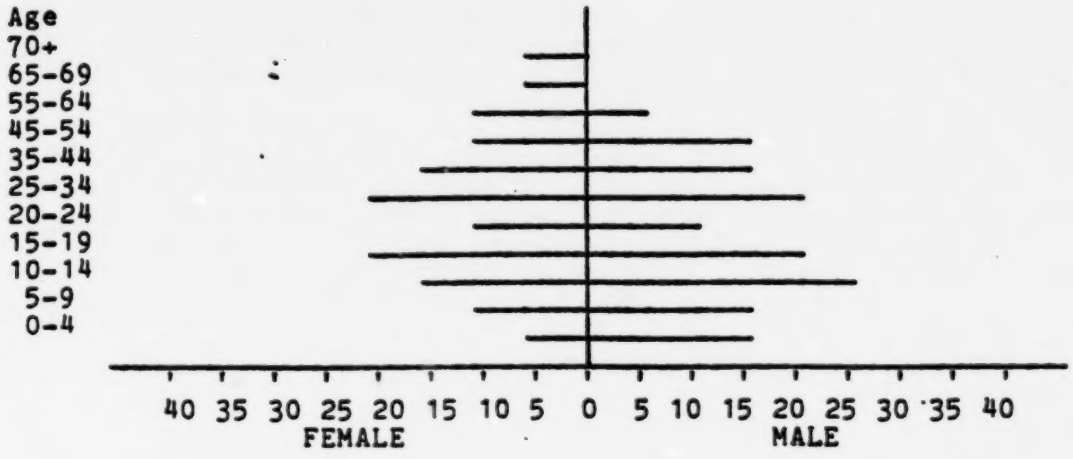
Year	Population	Increase	Growth %	Average Annual Growth %
1951	152			
1956	180	28	18.4	3.7
1961	202	22	12.8	2.6
1966	244	42	20.8	4.2
1971	232	-12	-4.9	-1.0
1976	248	14	5.6	1.1
1981	267	19	7.7	1.5

Source note: L'Anse au Clair Municipal Plan
1981 Census of Canada

Projected Future Population Growth:

At 2% per annum: 1986 - 294 1991 - 320

Population Structure by Age and By Gender - 1981



No. of Females - 122 No. of Males - 145

Footnotes:

Fifty-five percent of the population is under the age of 25; therefore there is potential for sustained population growth in this community.

Source Note: 1981 Census of Canada

B. COMMUNITY SERVICES

1. Water

Source:

Lake _____ River X Wells _____ Other No

Distribution:

Pipe X Truck _____ Individual Systems _____ None _____

Serving:

Government Buildings X Commercial Buildings X Residences X Standpipes ___

Treatment:

Sedimentation _____ Filtration _____ Chlorination X
Fluoridation _____ None _____

2. Sewage

Collection System:

Pipe X Truck ____ Individual Systems ____ None ____

Serving:

Government Buildings X Commercial Buildings X Residences X

Disposal:

Lagoon X Septic Tanks ____ Treatment Plant ____ None ____

---

3. Solid Waste Disposal

Garbage Collection Organized: Yes X No ____
Landfill Site Utilized: Yes ____ No X
Other: Incinerator in Forteau Yes X No ____

---

4. Police Protection

R.C.M.P.: Yes X No ____

Patrolled from: Forteau

---

5. Fire Protection Organized

Organized: Yes X No ____

Equipment: Hydrants

C. COMMUNITY FACILITIES

1. Health

Clinic in Community: Yes _____ No X

Size of Facility: _____

Staff: Doctors: _____ Nurses: _____

Other: Medical facilities in Forteau

2. Education

School located in community: Yes X No _____

Grades: Kindergarten to Grade 6

Size: N/A Classrooms: 3 Teachers: 3

3. Residential

(1)	Number of occupied private dwellings:	65
(2)	Number of houses with sewer and water:	100% have water; most have septic tanks
(3)	Housing Condition:	55, very good; 5 need minor repairs; 5 need major repairs
(4)	Number of owned homes:	60
(5)	Number of rented homes:	5
(6)	Number of single detached homes:	55
(7)	Number of single attached homes:	5
(8)	Average number of persons per private household:	4.1
(9)	Dwellings heated by steam or hot water:	10
(10)	Dwellings heated by hot air:	40
(11)	Dwellings heated with stove or space heater:	5
(12)	Dwellings heated by electric heat:	0
(13)	Other:	0

4. Community/Institutional/Commercial/Industrial Buildings

Church	General Store
General Store	General Store
Groceteria	Building Supply Store
Restaurant	Office Building (AVCO)
Garage	Garage
Gas Station	Gas Station
Hotel	Cabins (7 housekeeping units)

D. ECONOMIC ACTIVITIES

1. Fishery
2. Agriculture
3. Tourism

E. COMMUNICATION LINKS

			Comments
Post Office	Yes X	No	local
Television	Yes X	No	CBC
Radio	Yes X	No	CBC, CFCB
Telephone	Yes X	No	Nfld. Telephone D.D.D
High Frequency Radio	Yes	No X	
Operated By:			

F. TRANSPORTATION LINKS

1. Access to Community By Scheduled Services

	Carrier	Type
Air	Labrador Airways Quebec Air	Scheduled & Charter
Marine	Ferry Service	from St. Barbe to Blanc Sablon
Bus	Not Available	
Other	Gravel road connects all Straits communities	

2. Local Transportation

	Yes	No	Type
Boats	X		
Snowmobiles	X		
Cars	X		
Heavy Vehicles	X		
Other	X		Taxi Service

1982 ENERGY PROFILE

LOAD CENTER: L'Anse au Loup COMMUNITY: L'Anse au Clair

	ELECTRICITY (kwh)	FURNACE OIL (litres)	STOVE OIL (litres)	HEAVY FUEL OIL (litres)	FUELWOOI (tonnes
Residential	558 749		190 936		65
Commercial	142 341				
Industrial					
Government	142 341				
Street Lighting	4 158				
TOTAL	847 589		190 936		65

1982 ENERGY PROFILE

LOAD CENTER: L'Anse au Loup COMMUNITY: L'Anse au Clair

	ELECTRICITY (GJ)	FURNACE OIL (GJ)	STOVE OIL (GJ)	HEAVY FUEL OIL (GJ)	FUELWOOD (GJ)	TOTAL (GJ)
Residential	2,011		7,194		5,273	14,478
Commercial	512					512
Industrial						
Government	512					512
Street Lighting	15					15
TOTAL	3,051		7,194		5,273	15,517

4.6.4 REMOTE COMMUNITY ANALYSIS

Community Profile: L'Anse au Loup, Labrador

Status: Incorporated

Location: 51° 27' N
56° 53' W

Sources of Information:

Publications and Articles

Arco Co. Ltd. and Terpstra Engineering Ltd., "L'Anse au Loup Municipal Plan," May 1980.

Them Days Magazine, "Alluring Labrador," October 1980.

Place Name Codes of Newfoundland and Labrador, January 1981.

Selected Characteristics - Newfoundland - 1981 Census of Canada.

Interviews and Correspondence

Newfoundland Statistics Agency, May 1981.

Statistics Canada, May 1983.

Newfoundland and Labrador Hydro/Power Distribution District, May 19

Royal Canadian Mounted Police, June 1983.

Department of Municipal Affairs and Housing, May 1983.

Woodward's Oil Limited, June 1983.

Department of Health, June 1983.

Department of Transportation, June 1983.

Intergovernmental Affairs Secretariat, June 1983.

A. History and Current Status

1. L'Anse au Loup, first established by the French in the early 1700's, was also settled by English, Scots and Irish. As early as 1778 there was a thriving fishing and sealing industry established by Noble and Pinson from England.

L'Anse au Loup is the regional centre for electric power generation, fuel supply, fish processing and some government services.

2. Demographics

1981 Population: 589

Historic Population

Year	Population	Increase	Growth %	Average Annual Growth %
1945	217			
1951	268	51	23.5	3.9
1956	291	23	8.6	1.7
1961	343	52	17.9	3.6
1966	400	57	16.6	3.3
1971	448	48	12.0	2.4
1976	531	83	18.5	3.7
1981	589	58	11.0	2.2

Footnotes:

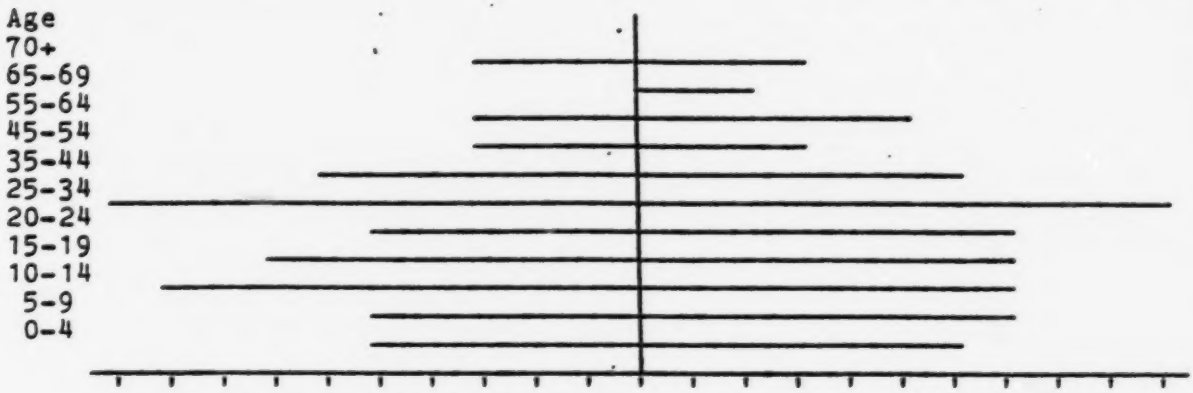
There has been a steady population increase.

Source Note: L'Anse au Loup Municipal Plan, May 1980.

Projected Future Population Growth:

1986 - 648 1991 - 707

Population Structure by Age and By Gender - 1981



No. of Females - 280 No. of Males - 309

Footnotes:

Over 60% of the community's population is under 25. This shows great potential for sustained population growth in the community.

Source Note: 1981 Census of Canada

B. COMMUNITY SERVICES

1. Water

Source:

Lake _____ River X Wells X Other No

Distribution:

Pipe X Truck _____ Individual Systems X None _____

Serving:

Government Buildings X Commercial Buildings X Residences X Standpipes ___

Treatment:

Sedimentation _____ Filtration _____ Chlorination X
Fluoridation _____ None _____

2. Sewage

Collection System:

Pipe _____ Truck _____ Individual Systems __X__ None _____

Serving:

Government Buildings __X__ Commercial Buildings __X__ Residences __X__

Disposal:

Lagoon ____ Septic Tanks __X__ Treatment Plant ____ None ____

---

3. Solid Waste Disposal

Garbage Collection Organized: Yes __X__ No _____
Landfill Site Utilized: Yes __X__ No _____
Other: Yes _____ No __X__

---

4. Police Protection

R.C.M.P.: Yes __X__ No _____

Patrolled from: Forteau

---

5. Fire Protection Organized

Organized: Yes __X__ No _____

Equipment: Hydrants

C. COMMUNITY FACILITIES

1. Health

Clinic in Community: Yes _____ No X

Size of Facility: _____

Staff: Doctors: _____ Nurses: _____

Other: Medical services at Forteau.
Visiting doctor from St. Anthony.

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2. Education

School located in community: Yes X No _____

Grades: Kindergarten to Grade 6

Size: N/A Classrooms: 4 Teachers: 4

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3. Residential

(1)	Number of occupied private dwellings:	130
(2)	Number of houses with sewer and water:	100%
(3)	Housing Condition:	very good, 50%; good, 28%; fair, 15%; poor, 7%
(4)	Number of owned homes:	125
(5)	Number of rented homes:	5
(6)	Number of single detached homes:	120
(7)	Number of single attached homes:	
(8)	Average number of persons per private household:	4.5
(9)	Dwellings heated by steam or hot water:	0
(10)	Dwellings heated by hot air:	75
(11)	Dwellings heated with stove or space heater:	55
(12)	Dwellings heated by electric heat:	0
(13)	Other:	0

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4. Community/Institutional/Commercial/Industrial Buildings

General Store	Restaurant
General Store	Lounge
General Store	Garage
General Store	Garage
General Store	Bank
General Store	Library
Nfld. Liquor Corp.	Construction Company
Craft Centre	Furniture & Appliance Store
Museum	Community Hall
Fish Plant	Indoor Swimming Pool
Church	

D. ECONOMIC ACTIVITIES

1. Fishery
2. Heavy Equipment Contracting
3. Service Industries

E. COMMUNICATION LINKS

			Comments
Post Office	Yes X	No	A0K 3L0
Television	Yes X	No	CBC
Radio	Yes X	No	CBC & CFCB
Telephone	Yes X	No	Nfld. Telephone D.D
High Frequency Radio	Yes	No X	
Operated By:			

F. TRANSPORTATION LINKS

1. Access to Community By Scheduled Services

	Carrier	Type
Air	Labrador Airways	scheduled & charter
Marine	Ferry Service	From St. Barbe to Blanc Sablon
Bus	Not Available	
Other	Labrador Straits communities connected by gravel road	

2. Local Transportation

	Yes	No	Type
Boats	X		
Snowmobiles	X		
Cars	X		
Heavy Vehicles	X		
Other	X		Taxi Service

G. DIESEL ELECTRIC GENERATION

1. Owner: Newfoundland and Labrador Hydro/Power Distribution District

2. Diesel Type: 1 - 600 kw Cat. with CANRON Generator
1 - 800 kw Cat. with CANRON Generator
1 - 850 kw Cat. with Kato Generator

3. Diesel Fuel Consumption:

	1981	1982
Annual Fuel Use (litres)	1,921,563	2,052,982
Annual Fuel Cost	$526,830.00	$653,726.00
Cost per litre	$0.27	$0.39
Cost Increase		44%

4. Electricity Demand - Historical and Predicted (mwh):

1980	5633	1985	7175
1981	5891	1986	7435
1982	6456	1987	7704
1983	6685	1988	7984
1984	6926		

5. Peak Load Demand - Historical and Predicted (kw):

1980	1368	1985	1773
1981	1440	1986	1842
1982	1584	1987	1912
1983	1645	1988	1986
1984	1708		

H. ASSESSMENT OF RESOURCES - L'Anse au Loup - Total Load Centre

Small Scale Hydro Potential

L'Anse au Loup is the load center and location of a diesel generating plant which serves eleven communities along a 65 km. stretch of the south coast of Labrador along the Strait of Belle Isle. Although it would be preferable from an operational point of view to have any potential hydro development located close to the diesel plant, potential sites anywhere on the system could be considered as potential developments. In this light, then, there are six possible sites located within 8 km. of the nearest transmission line.

The closest site to the diesel plant is located on an unnamed river, which has been named L'Anse au Loup River for the purpose of identification and is 1.6 km. from the nearest point on the transmission line. The site has an estimated nominal capacity of 540 kw. through a head of approximately 14 M.

The next site is located on Forteau Brook, 8 km. from the transmission line. The nominal capacity is 425 kw. through a head of approximately 8 M.

The next closest site to the diesel plant is located on an unnamed river (fictitiously named the Little Pinware River), 0.7 km. from the transmission line. This site has a nominal capacity of 415 kw. through a head of approximately 15 M.

Next is a site at L'Anse au Clair, located 0.7 km. from the transmission line. This site has a nominal capacity of 390 kw. through a head of approximately 42 M.

Another site on Red Bay Brook is located very near the transmission line. This site has a nominal capacity of 250 kw. through a head of approximately 20 M.

Wood Resources

The published data base on the inventory of fuelwood resources in this area is inadequate to allow for the formulation of definitive conclusions about this alternative. The Statistics Canada data base for this area indicates that the number of households using wood as a primary fuel ranges from a low of 19% in L'Anse au Loup to a high of 51% in Pinware and Red Bay. The other communities in the area for which this information is available indicates this consumption to be as follows: Forteau, 43%; L'Anse au Clair, 42%; West St. Modeste and Capstan Island, 34%. The variation between communities of the proportion of households using wood as a primary fuel cannot be explained from the existing data base, and the only way to estimate the potential to increase the use of this source as a primary and secondary fuel is through further research.

Peat Resources

No published fuel peat inventories are available for this area, and consequently no definitive conclusions can be made about this alternative.

Wind Resources

The published data base on the wind regime for this area is insufficient to formulate definitive conclusions about this alternative.

Cogeneration - District Heating

Information obtained from Newfoundland and Labrador Hydro indicates that there is no potential for this alternative in this area.

Conservation Measures

No data base exists to evaluate conservation options.

Assessment

There are two promising sites for small scale hydroelectric development in the L'Anse au Loup area. The site on L'Anse au Loup River, near the community of L'Anse au Loup, was identified in the 1979 inventory study conducted by Shawmont Newfoundland Limited. This site would develop 420 kw. of electric power and would have a capital cost of between $1.7 and $2.3 million. The Annual Equivalent Cost of energy for this site is estimated to be approximately $0.19 per kwh.

The second site was identified in a study for the installation of water and sewer services for the community of Red Bay. This study was conducted by Bishop and Forbes (1978) Ltd. This site on Northern Brook, which would be developed in conjunction with the water and sewer system, would develop 335 kw. of electric power and would have a capital cost of approximately $2,150,000. This would yield an Annual Equivalent Cost of energy of approximately $0.16 per kwh. based on the 60% load factor used in the study.

Either of these two sites appears to be economically viable. The site on L'Anse au Loup River has the advantage of being close to the load center and the existing diesel generating plant. The major disadvantage of this site is the large Atlantic Salmon population which inhabits the river at certain times of the year.

The capital cost of the Red Bay site includes approximately $1,000,000 for the upgrading of the transmission line from L'Anse au Loup to Red Bay. This upgrading is required to permit the backfeeding of power from Red Bay. Exclusive of this line upgrading cost, Red Bay is clearly the more economically attractive site, with an Annual Equivalent Cost of energy of approximately $0.09 per kwh.

The data base on wood, peat, wind and the potential for conservation is either non-existent or inadequate to seriously evaluate these options. More detailed research and analysis would have to be conducted before these options could be promoted or dismissed as potential contributors to heating and/or electrical generation requirements.

1982 ENERGY PROFILE

LOAD CENTER: L'Anse au Loup COMMUNITY: L'Anse au Loup

	ELECTRICITY (kwh)	FURNACE OIL (litres)	STOVE OIL (litres)	HEAVY FUEL OIL (litres)	FUELWOOD (tonnes)
Residential	948,702		600,084		652
Commercial	102,187				
Industrial	232,800				
Government	166,726				
Street Lighting	129,789				
TOTAL	1,580,204		600,084		652

1982 ENERGY PROFILE

LOAD CENTER: L'Anse au Loup COMMUNITY: L'Anse au Loup

	ELECTRICITY (GJ)	FURNACE OIL (GJ)	STOVE OIL (GJ)	HEAVY FUEL OIL (GJ)	FUELWOOD (GJ)	TOTAL (GJ)
Residential	3 415		22 611		5 273	31 299
Commercial	368					368
Industrial	838					838
Government	600					600
Street Lighting	467					467
TOTAL	5 689		22 611		5 273	33 572

APPENDIX 3

Meteorological and Hydrometric Records

Table 1. Total Precipitation for Cartwright, Goose Bay, Blanc Sablon

Table 2. Blanc Sablon Monthly Total Precipitation Records, 1966-1980

Table 3. Cartwright - Monthly Total Precipitation Records, 1966-1980

Table 4. Goose Bay - Monthly Total Precipitation Records, 1966-1980

Figure 1. Total Precipitation Isohyet, 1931-1960

Figure 2. Streamflow Loss Isohyet, 1931-1960

Table 5. Saint Paul River, Monthly and Annual Mean Discharge, 1967-1981

Table 6. Eagle River, Monthly and Annual Mean Discharge, 1966-1982

Table 7. Alexis River, Monthly and Annual Mean Discharge, 1978-1982

Table 1 Total Precipitation Monthly and Annual Means
(from Canadian Climate Normals, 1951-1980)

Source		JAN.	FEB.	MAR.	APR.	MAY	JUNE	JULY	AUG.	SEPT.	OCT.	NOV.	DEC.	YEAR	CODE
	Newfoundland														
1	Cartwright	89.2	67.8	93.3	80.6	62.9	78.0	83.2	81.9	90.3	71.8	79.8	74.9	953.7	1
2	Goose Bay	74.4	60.0	72.2	61.2	63.8	93.1	105.1	103.2	88.6	76.6	75.2	72.7	946.1	1
	Quebec														
3	Blanc Sablon	133.4	109.0	91.0	71.7	72.4	93.8	96.9	108.0	88.2	91.8	98.0	106.2	1060.4	8

Source: Canadian Climate Normals, 1951-1980, Environment Canada, Atmospheric Environment Service, vol. 1, page 108 (for item 1), page 116 (for item 2); vol. 2, p. 24 (for item 3).

Table 2 Blanc Sablon - Monthly Precipitation for 1966-1980 **

Year	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Mean
1966*	2.66	1.20	0.74	2.45	3.04	2.09	6.81	3.72	5.45	2.31	4.13	3.87	
1967	0.85	3.13	2.80	0.60E	4.36	2.72	8.83	4.88	4.13	3.36E	3.30	3.75E	
1968	3.63	3.72E	4.32	4 [illegible]	0.70	5.55	1.78	5.80E	3.64	5.91	3.10E	6.98E	
1969	6.40E	1.41E	4.51E	2. [illegible]E	3.42	2.89	4.44E	4.21	1.36	1.97	4.30	4.21	
1970	1.28	-	3.22	1.36	3.56	4.71	6.16	3.80E	2.34	7.88	3.13	-	
1971	2.80	3.92	5.05E	-	2.16E	2.11	3.98	6.58	6.42	-	-	-	
1972*	M	M	M	M	2.09	4.78	3.61	5.07	4.75	2.96	2.92	1.60	
1973	-	6.64E	-	0.33	-	2.45	M	3.10	3.43	M	3.27	-	
1974	1.13	-	M	-	-	M	4.27	2.10	3.04	5.20	4.04	-	
1975	2.62	-	-	-	2.99	2.55	3.06	-	4.45	-	-	-	
1976	4.61	2.98	5.04	2.38	2.51	1.86	1.68	5.87	3.15	3.10	4.83	M	
1977	140.2	79.6	58.4	69.1	54.9	50.6	81.0	88.4	99.3	108.5	34.7	108.6	
1978	174.5	93.0	113.3	58.5	61.2	107.1	98.0	64.1	29.2	110.6	49.6	102.7	
1979	113.1	60.2	61.9	40.4	M	110.6	130.7	156.8	145.6	119.2	114.0	98.4	
1980	115.0	62.1	63.7	28.8	59.4	138.8	102.4	53.5	118.9	72.7	94.5	106.8	

Notes: (1) 1966-1976 recordings are in inches, 1977-1980 in millimeters

(2) E - Estimated

(3) M - Missing

*First four months of 1972 are missing

**Source: Environment Canada, Atmospheric Environment Service, internal files

Table 3 Cartwright - Monthly Precipitation for 1966-1980*

Year	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Mean
1966*	76.5	56.9	60.7	51.6	72.1	69.3	94.2	64.3	53.6	148.6	40.1	62.0	849.9
1967	51.3	70.6	77.7	61.7	47.5	59.4	93.2	121.9	88.4	37.8	63.5	88.6	861.6
1968	99.1	83.3	115.6	53.6	104.6	114.0	79.5	67.1	96.8	150.6	90.9	99.1	1154.2
1969	79.0	32.0	81.3	37.3	75.9	70.4	73.7	56.9	54.4	50.8	81.3	99.1	792.1
1970	53.8	39.6	88.7	59.8	59.1	75.3	92.8	82.9	72.3	82.0	84.9	78.7	917.3
1971	127.8	37.1	231.9	65.0	76.2	119.9	32.5	110.2	67.8	44.5	97.5	87.4	1097.8
1972	35.1	38.4	64.5	106.9	44.5	83.6	50.0	92.7	150.6	34.0	65.5	38.9	804.7
1973	63.2	131.6	86.6	25.9	47.0	64.5	118.6	47.0	39.4	20.6	99.3	58.4	802.1
1974	43.2	128.0	134.6	129.0	90.9	69.3	65.3	82.6	40.1	72.6	104.6	74.7	1034.9
1975	25.7	15.7	167.6	111.5	44.2	58.7	41.1	51.3	75.9	95.3	89.9	100.8	877.7
1976	74.4	17.0	70.6	161.3	21.8	31.0	48.5	116.8	147.6	75.7	80.8	142.2	987.7
1977	150.5	86.9	70.1	88.5	148.4	56.2	94.5	132.2	213.6	86.1	58.0	103.2	1269.2
1978	128.9	124.0	80.2	218.4	92.9	121.5	52.9	106.5	81.1	90.7	43.5	122.9	1263.5
1979	63.6	148.8	57.9	63.6	77.2	102.2	143.2	127.4	120.3	108.4	71.2	69.2	1153.0
1980	98.5	99.3	35.0	58.4	76.2	182.1	67.2	42.4	97.7	133.9	154.7	110.7	1156.1

Mean													
1961-70	84.6	56.2	88.7	59.8	59.1	75.3	92.8	82.9	72.3	82.0	84.9	78.7	917.3
1971-80	81.1	82.7	99.9	102.9	71.9	88.9	71.4	89.0	103.4	76.2	86.5	90.8	1044.7

*Source: Environment Canada, Atmospheric Environment Service, internal files

Table 4 Goose Bay - Monthly Precipitation for 1966-1980 *

Year	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Mean
1966	54.4	30.7	31.5	19.8	92.7	92.5	201.2	90.2	46.5	152.1	58.2	109.0	978.8
1967	68.1	52.6	16.5	24.6	45.0	51.8	125.5	99.8	72.9	36.3	85.1	87.6	765.8
1968	71.9	98.3	95.8	66.5	45.7	61.2	127.3	129.3	84.8	132.8	98.6	106.2	1118.4
1969	46.7	36.3	75.2	36.8	59.2	89.4	87.1	148.3	112.0	53.3	89.7	143.8	977.8
1970	36.3	48.3	94.5	59.7	77.2	103.1	121.2	109.0	63.0	62.0	35.8	71.6	881.7
1971	78.0	39.4	138.2	70.6	78.5	104.9	99.1	141.0	82.8	31.5	150.9	49.5	1064.4
1972	55.1	48.0	73.9	55.1	37.1	112.5	56.4	136.4	79.8	62.7	59.9	49.3	825.2
1973	78.5	80.3	35.8	29.2	33.3	113.0	120.7	65.3	19.8	69.6	77.0	115.6	838.1
1974	23.9	75.9	53.8	69.9	38.4	59.4	62.0	83.8	46.5	88.4	68.1	50.0	720.1
1975	25.1	11.4	131.1	102.1	19.3	76.2	68.3	61.7	94.7	57.2	81.0	118.6	846.7
1976	88.9	39.6	52.6	102.1	29.5	19.8	94.5	142.5	162.8	82.8	61.2	57.4	933.7
1977	106.5	60.7	31.4	56.6	116.1	58.0	96.6	106.9	148.0	78.4	65.2	79.0	1005.4
1978	78.0	72.5	79.9	104.2	56.8	158.5	90.6	95.4	91.7	97.1	36.3	50.7	1011.7
1979	60.5	82.6	65.2	48.5	82.0	109.1	141.1	145.8	105.0	102.3	72.2	100.4	1114.7
1980	75.7	80.9	45.3	33.4	108.3	192.2	110.3	48.7	132.3	96.8	131.7	88.5	1144.1

Mean													
1961-70	63.1	54.6	72.0	39.3	71.9	99.4	136.7	96.1	76.5	88.1	75.3	80.7	953.7
1971-80	67.0	59.1	70.7	67.4	59.9	100.4	94.0	102.8	96.3	76.7	80.3	75.9	950.5

*Source: Environment Canada, Atmospheric Environment Service, internal files

Figure 1
Total Precipitation Isohyet,
1931-1960

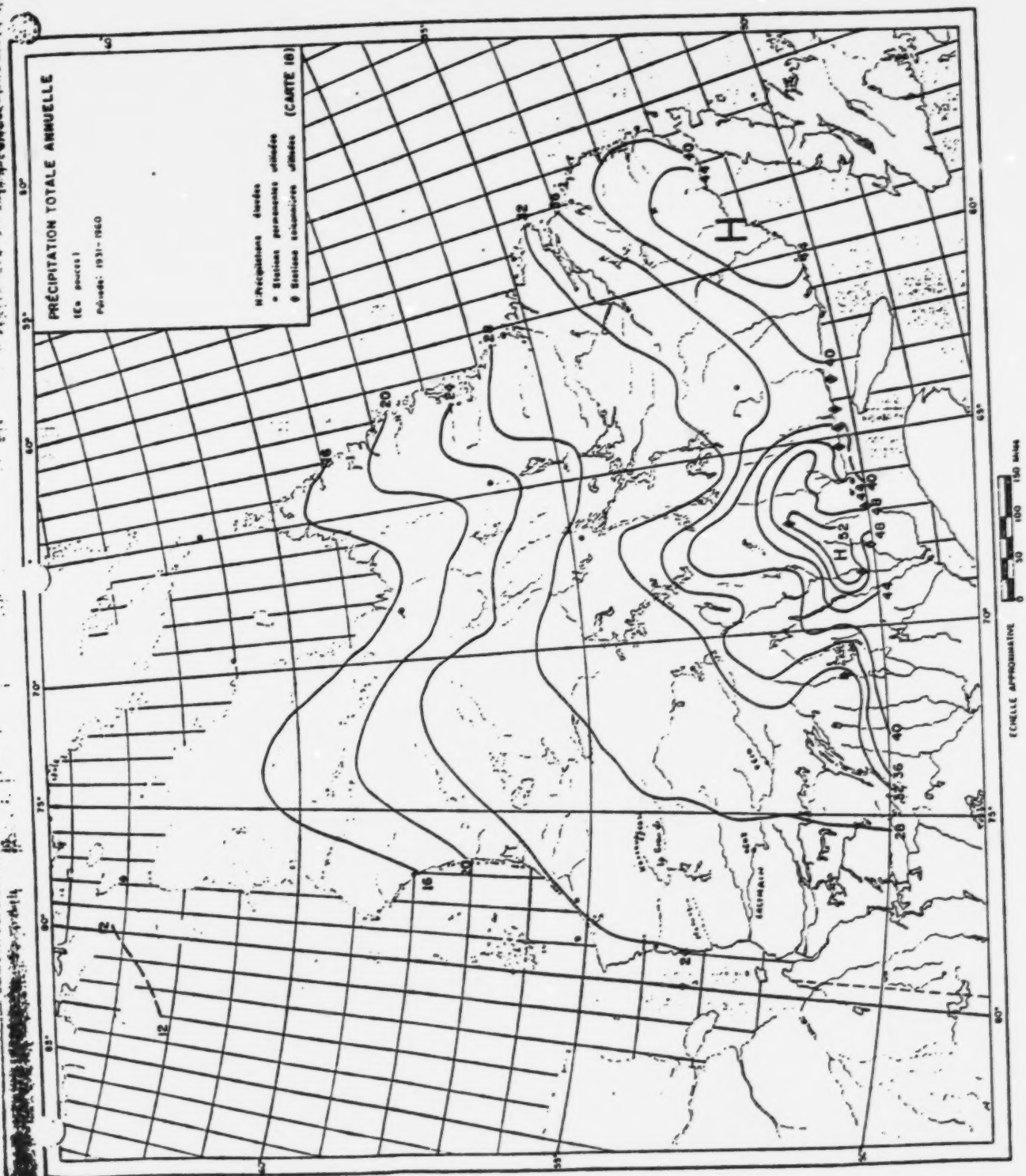

Figure 2
Streamflow Loss Isohyet,
1931-1960

Table 5 Saint Paul's River Monthly and Annual Mean Discharge

Annual	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Mean
1967	-	-	-	-	-	-	-	161	177	-	-	-	-
1968	40.7	45.1	26.3	50.4	386	266	162	212	191	182	123	74.2	147
1969	56.6	106	77.7	55.1	470	564	162	140	87.6	97.0	137	227	182
1970	102	72.6	44.6	51.0	319	277	221	101	73.4	207	113	81.9	139
1971	53.6	35.4	25.4	70.5	600	210	115	112	213	90.1	132	67.4	145
1972	-	-	-	-	-	-	-	-	-	178	-	-	-
1973	21.4	14.9	13.9	14.4	633	380	217	124	81.5	101	77.5	77.4	148
1974	45.9	21.6	17.0	18.8	218	536	136	75.3	64.0	120	87.7	77.4	118
1975	29.0	14.3	13.8	16.4	437	300	69.5	95.3	224	122	169	82.0	131
1976	40.0	37.8	24.4	68.6	494	124	64.6	171	233	148	108	70.4	132
1977	73.8	41.5	29.8	42.2	533	693	90.0	107	182	240	179	85.5	192
1978	52.0	28.6	23.2	23.1	678	685	143	101	115	250	81.2	40.7	186
1979	47.7	65.3	181	195	580	116	104	182	176	150	71.9	45.6	160
1980	42.8	30.6	25.2	45.2	592	518	264	157	113	183	211	66.2	188
1981	48.0	95.3	79.9	-	-	-	147	117	90.3	-	-	-	-
Mean	50.3	46.8	44.8	54.2	495	389	146	133	144	159	124	83.0	156

DRAINAGE AREA = 6630 km^2

Table 6 Eagle River Monthly and Annual Mean Discharges *

Annual	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Mean
1966	-	-	-	-	-	-	-	-	-	435.0	255.0	105.0	-
1967	66.4	49.3	39.7	35.7	106.0	538.0	274.0	452.0	228.0	-	-	-	-
1968	-	-	-	-	-	-	-	-	-	348.0	266.0	125.0	-
1969	98.9	86.2	78.7	74.6	494.0	1180.0	360.0	207.0	133.0	232.0	226.0	144.0	276.2
1970	87.5	63.7	52.2	48.6	702.0	648.0	327.0	300.0	134.0	175.0	124.0	74.0	228.0
1971	53.6	43.2	37.2	197.0	1400.0	909.0	263.0	187.0	283.0	288.0	135.0	83.0	323.3
1972	45.4	31.2	24.1	20.7	273.0	1310.0	224.0	242.0	294.0	261.0	101.0	50.9	239.8
1973	36.9	29.8	26.5	32.8	1140.0	585.0	270.0	148.0	94.2	100.0	107.0	61.7	219.3
1974	43.0	34.4	29.6	29.0	454.0	1470.0	375.0	213.0	109.0	220.0	95.2	36.3	259.0
1975	22.4	17.2	14.3	12.4	276.0	813.0	263.0	201.0	291.0	170.0	117.0	62.8	188.3
1976	46.3	37.7	32.6	162.0	927.0	396.0	119.0	264.0	521.0	336.0	176.0	120.0	261.5
1977	63.2	44.3	37.3	64.4	739.0	1570.0	449.0	425.0	189.0	210.0	102.0	75.0	330.7
1978	54.7	43.8	35.9	47.2	517.0	1550.0	386.0	169.0	242.0	515.0	175.0	92.9	319.0
1989	68.1	69.1	69.0	-	-	337.0	288.0	333.0	292.0	290.0	194.0	67.0	-
1980	44.1	34.4	29.3	-	-	1010.0	533.0	339.0	187.0	333.0	352.0	143.0	-
1981	89.0	68.0	57.1	76.8	1260.8	1090.0	400.0	271.0	158.0	398.0	255.0	91.1	351.2
1982	57.7	43.8	35.7	34.7	324.0	1390.0	502.0	203.0	258.0	129.0	155.0	108.0	270.1
Mean	58.5	46.4	39.9	64.3	662.5	986.4	335.5	263.6	227.5	277.5	177.2	90.0	269.1

DRAINAGE AREA = 10,900 km^2

* Source: Water Quantity Survey, Environment Canada, Inland Waters Directorate, Water Resources Branch

Table 7 Alexis River Monthly and Annual Mean Discharges *

Annual	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Mean
1978	9.7	7.3	6.2	10.6	188.0	160.0	41.2	33.6	49.1	75.1	19.8	12.8	51.1
1979	22.9	23.6	19.7	38.2	108.0	32.1	33.9	50.6	74.2	66.8	29.2	11.9	42.6
1980	7.8	5.8	5.2	26.5	246.0	208.0	64.6	38.4	38.1	72.0	103.0	30.7	70.5
1981	17.7	12.2	9.3	13.0	252.0	130.0	64.0	49.4	35.4	76.0	40.8	12.1	59.3
1982	7.8	6.4	5.8	6.4	172.0	164.0	88.9	39.9	32.2	24.6	44.8	19.7	31.0
Mean	13.2	11.1	9.2	18.9	193.2	138.8	58.5	42.4	45.8	62.9	47.5	17.4	54.9

DRAINAGE AREA = 2310 km^2

* Source: Water Quantity Survey, Environment Canada, Inland Waters Directorate, Water Resources Branch

APPENDIX 4

Capital Cost Estimates

ITEM NO.	DESCRIPTION		UNIT OF MEASURE	QUANTITY	UNIT COST	TOTAL
	SUMMARY					
Page						
2	Access Roads					97 000
3	Intake/Diversion Weir					179 900
4	Penstock					394 000
5	P-H Civil					98 260
6	E/M Equipment (powerhouse)					239 400
	S/T Direct Costs					1 008 560
	Indirect Construction Costs @ 5%					50 430
	S/T Construction Cost					1 058 990
	Eng.& Owners Costs @ 15%					158 850
	S/T					1 217 840
	Contingency @ 10%					121 800
	Total Cost					1 339 640

REMARKS: Jan. 1985 Prices

COST ESTIMATE

PROJECT: Lanse Au Clair

Summary Cost Estimate

314 kw Scheme

Shawinigan

A DIVISION OF Lavalin

DATE: Feb.12/85 CONTRACT: PAGE 1

003

ITEM NO.	DESCRIPTION		UNIT OF MEASURE	QUANTITY	UNIT COST	TOTAL
1	Intake Access Road					
	Borrow Materials		m^3	1000	10	10 000
	600mm Culvert		m	12	125	1 500
						11 500
2	Powerhouse Access Road					
	Borrow Materials		m^3	1000	10	10 000
	600mm Culvert		m	6	125	750
						10 750
3	Penstock Access Road					
	Clearing		Ha	0.5	1500	750
	Grubbing		m^3	1000	8	8 000
	Backfill		m^3	5000	10	50 000
	Rock Excavation		m^3	500	25	12 500
	600mm Culvert		m^3	25	125	3 125
						74 375
	Subtotal					96 625
	Rounding					375
	Total Access Roads					97 000

REMARKS:

COST ESTIMATE

PROJECT: Lanse Au Clair

Civil Works - Access Roads

192/314 kw Scheme

Shawinigan

A DIVISION OF **Lavalin**

ITEM NO.	DESCRIPTION		UNIT OF MEASURE	QUANTITY	UNIT COST	TOTAL
	Intake/Diversion Weir					
	Stripping		m^2	1500	5.0	7 500
	Excavation		m^3	2500	7.0	17 500
	Compacted Fill		m^3	3680	25.0	92 000
	Sand Drain		m^3	80	30.0	2 400
	Concrete Wall and Intake		m^3	37	600.0	22 200
	Concrete Sill and Cut-off		m^3	40	500.0	20 000
	Fishway		LS			10 000
	S/T Civil					171 600
	Equipment					
	Head Gate					4 600
	Trash Rack					3 700
	S/T Equipment					8 300
	Total					179 900

REMARKS:

COST ESTIMATE

PROJECT: Lanse Au Clair

Civil Works - Intake Weir

314 kw Scheme

Shawinigan

A DIVISION OF Lavalin

DATE: Feb.12/85 CONTRACT: PAGE 3

ITEM NO.	DESCRIPTION		UNIT OF MEASURE	QUANTITY	UNIT COST	TOTAL
	32" Nominal (800mm) Polyethylene Pipe					
	Purchase					
	Series 45		m	625		
	Series 60		m	168		
	Series 80		m	76		
	Series 100		m	131		
						337 200
	Flange Adaptor Kits			8	1900	15 200
	Installation					9 600
	Rental Fusing Equip.					5 000
	Labour for Technician					3 000
	Travel/Expenses					12 000
	Additional Equip. and Labour					29 600
	Provisions for Penstock Dewatering Facilities		LS			12 000
	Total Penstock Cost					394 000

REMARKS:

(1) Includes taxes and freight on pipe joining, equipment

COST ESTIMATE

PROJECT: Lanse Au Clair
Civil Works - Penstock
314 kw Scheme

Shawinigan
A DIVISION OF Lavalin

DATE: Feb.12/85 CONTRACT

ITEM NO.	DESCRIPTION		UNIT OF MEASURE	QUANTITY	UNIT COST	TOTAL
	Powerhouse Civil Works					
	Excavation		m^3	1265.0	7.0	8 860
	Concrete		m^3	33.0	600.0	19 800
	Superstructure		m^2	48.0	1200.0	57 600
	Building Services		LS			12 000
	Total Powerhouse Civil					98 260

REMARKS:

COST ESTIMATE

PROJECT: Lanse Au Clair
Civil Works - Powerhouse
192/314 kw Scheme

Shawinigan
A DIVISION OF Lavalin

DATE: Feb.12/85 CONTRACT: PAGE 5

ITEM NO.	DESCRIPTION		UNIT OF MEASURE	QUANTITY	UNIT COST	TOTAL
	Electrical and Mechanical Equipment					
1	Turbine 443 hp. 720 RPM Crossflow			1		92 000
	Nethead 66.44m					
2	Generator 393 kva. 720 RPM 3Ø			1		82 200
3	Transformer 393 kva. 3Ø 0.6/12.5kv			1		9 700
4	Aux. Mechanical					25 300
5	Aux. Electrical					23 700
6	Butterfly Valves 800mm			1		6 500
	Total Powerhouse Equipment					239 400

REMARKS: Includes all switchgear, controls, governors, etc.

COST ESTIMATE

PROJECT: Lanse Au Clair
Powerhouse E/M Equipment
314 kw Scheme

Shawinigan
A DIVISION OF Lavalin

Feb 12/85

ITEM NO.	DESCRIPTION		UNIT OF MEASURE	QUANTITY	UNIT COST	TOTAL
	SUMMARY					
Page						
2	Access Roads					97 000
3	Intake/Diversion Weir					175 700
4	Penstock					274 000
5	P-H Civil					98 260
6	E/M Equipment (powerhouse)					179 400
	S/T Direct Costs					824 360
	Indirect Construction Costs @ 5%					41 220
	S/T Construction Cost					865 580
	Eng.& Owners Costs @ 15%					129 840
	S/T					995 420
	Contingency @ 10%					99 500
	Total Cost					1 094 920

REMARKS:

COST ESTIMATE

PROJECT: Lanse Au Clair

Summary Cost Estimate

192 kw Scheme

Shawinigan

A DIVISION OF Lavalin

DATE: Feb.12/85 CONTRACT: PAGE 1

ITEM NO.	DESCRIPTION		UNIT OF MEASURE	QUANTITY	UNIT COST	TOTAL
1	Intake Access Road					
	Borrow Materials		m^3	1000	10	10 000
	600mm Culvert		m	12	125	1 500
						11 500
2	Powerhouse Access Road					
	Borrow Materials		m^3	1000	10	10 000
	600mm Culvert		m	6	125	750
						10 750
3	Penstock Access Road					
	Clearing		Ha	0.5	1500	750
	Grubbing		m^3	1000	?	8 000
	Backfill		m^3	5000	10	50 000
	Rock Excavation		m^3	500	25	12 500
	600mm Culvert		m	25	125	3 125
						74 375
						96 625
	Subtotal					375
	Rounding					97 000
	Total Access Roads					

REMARKS:

COST ESTIMATE

PROJECT: Lanse Au Clair
Civil Works - Access Roads
192/314 kw Scheme

Shawinigan
A DIVISION OF Lavalin

Feb 12/85

ITEM NO.	DESCRIPTION		UNIT OF MEASURE	QUANTITY	UNIT COST	TOTAL
	Intake/Diversion Weir					
	Stripping		m^2	1500	5.0	7 500
	Excavation		m^3	2500	7.0	17 500
	Compacted Fill		m^3	3680	25.0	92 000
	Sand Drain		m^3	80	30.0	2 400
	Concrete Wall and Intake		m^3	37	600.0	22 200
	Concrete Sill and Cut-off		m^3	40	500.0	20 000
	Fishway		LS			10 000
	S/T Civil					171 600
	Equipment					
	Head Gate					2 300
	Trash Rack					1 800
	S/T Equipment					4 100
	Total					175 700

REMARKS:

COST ESTIMATE

PROJECT: Lanse Au Clair
Civil Works - Intake Weir
192 kw Scheme

Shawinigan
A DIVISION OF Lavalin

DATE: Feb.12/85 CONTRACT: PAGE 3

002

ITEM NO.	DESCRIPTION		UNIT OF MEASURE	QUANTITY	UNIT COST	TOTAL
	24" Nominal (630mm) Polyethylene Pipe					
	Purchase					
	Series 45		m	625		
	Series 60		m	160		
	Series 80		m	76		
	Series 100		m	122		
						223 500
	Flange Adaptor Kits			8	1345	10 760
	Installation					
	Rental Fusing Equip.					9 600
	Labour for Technician					5 000
	Travel/Expenses					3 000
	Additional Equip. and Labour for installation					12 000
						29 600
	Provisions for Penstock Dewatering Facilities		LS			10 000
	Rounding					140
	Total Penstock Cost					274 000

REMARKS:

(1) Includes taxes and freight on pipe joining equipment.

COST ESTIMATE

PROJECT: Lanse Au Clair

Civil Works - Penstock

192 kw Scheme

Shawinigan

A DIVISION OF Lavalin

ITEM NO.	DESCRIPTION		UNIT OF MEASURE	QUANTITY	UNIT COST	TOTAL
	Powerhouse Civil Works					
	Excavation		m^3	1265.0	7.0	8 860
	Concrete		m^3	33.0	600.0	19 800
	Superstructure		m^2	48.0	1200.0	57 600
	Building Services		LS			12 000
	Total Powerhouse Civil					98 260

REMARKS:

COST ESTIMATE

PROJECT: Lanse Au Clair
Civil Works - Powerhouse
192/314 kw Scheme

Shawinigan
A DIVISION OF Lavalin

DATE: Feb.12/85 CONTRACT: PAGE 5

ITEM NO.	DESCRIPTION		UNIT OF MEASURE	QUANTITY	UNIT COST	TOTAL
	Electrical and Mechanical Equipment					
1	Turbine 443 hp. 720 RPM Crossflow			1		72 500
	Nethead 65.22m					
2	Generator 240 kva. 1.Ø 780 RPM			1		59 800
3	Transformer 240 kva. 0.6Ø12.5 kv 1-Ø			1		6 700
4	Aux. Mechanical					19 900
5	Aux. Electrical					17 300
6	Butterfly Valves 630mm			1		6 500
	S/T Powerhouse Equipment					179 400

REMARKS: Includes all switchboard, controls, governors, etc.

COST ESTIMATE

PROJECT: Lanse Au Clair
Powerhouse E/M Equipment
192 kw Scheme

Shawinigan
A DIVISION OF Lavalin

DATE: Feb.12/85 CONTRACT: PAGE 6

APPENDIX 5

L'Anse au Loup Distribution System, Performance and Costs

HYDRO
PDD

THE BOARD OF TRUSTEES OF THE POWER DISTRIBUTION DISTRICT
OF NEWFOUNDLAND AND LABRADOR

Head Office: St. John's, Newfoundland A1A 2X8 • Telephone (709) 737-1400 • Telex 016-4503

1984 09 21

Fenco Newfoundland Ltd.
P.O. Box 8246
St. John's, Newfoundland.
A1B 3N4

Attention: H. Laban Davis/Dale Courage.

Subject: L'Anse Au Loup.

Dear Sirs:

I can provide you with some information with regard to your September 19, 1984 request.

By item number these remarks and information should be useful:

(1) Latest fuel cost for L'Anse Au Loup is $0.35/litre.

(2) See attached Historical Data sheet.
Note all costs in current dollars.

I have changed the format of your request from fixed and variable costs to the format attached. This is because the difference between a fixed cost and a variable cost is not clear cut.

The Diesel Net Efficiency can be readily calculated from this data.

(3) We in P.D.D. only forecast 5 years. If you require a 20-year forecast please let us know so that the Economic Analysis Department can look into it.

Year	1983 Actual	1984	1985	1986	1987	1988	1989
MWh	6860	7227	7574	7878	8195	8525	8866
kW	1680	1764	1855	1935	2018	2104	2194

L'ANSE AU LOUP

Historical Data:

Year	Fuel Consumption (ℓ)	Lube Oil (ℓ)	Net[1] kWh Consumption
1980	1,788,826	10,333	5,383,400
1981	1,921,563	11,945	5,731,800
1982	2,052,982	14,779	6,036,400
1983	2,156,222	18,009	6,353,800

(1) Net kWh Consumption = Gross Plant Production minus Station Service Consumption.

Year	Operating Costs[1]	Maintenance Costs[2]	Lube Oil	Diesel Fuel
1981	159,792	44,434	12,898	526,830
1982	185,719	59,747	17,827	653,726
1983	182,200	61,727	27,685	738,206

(1) Operating Costs exclude Diesel Fuel.

(2) Maintenance Costs include lube oil and all maintenance material besides related salaries.

(6) We can supply you with our Daily log sheets. You will have to draw up the load shape curves.

(7)

Diesel Machine #	kW	Year Purchased	1983 Operating Hours
231	850	1973	2,655
246	600	1973	3,597
247	600	1976	4,741
285	800	1981	5,058

Using the above information, you should be able to estimate the total hours each machine has been run since it was purchased.

(8) Nearly all the pole structure need to be changed if the line from Forteau to L'Anse Au Clair is to be upgraded to 3 Ø. This should cost approximately $400,000.

If you have any qestions, my telephone number is 737-1474.

Yours truly,

Shalom Auerbach

Shalom Auerbach
Distribution Engineer
Customer Services.

SA/cd.

APPENDIX 6

Correspondence with Fisheries and Oceans

Fenco Newfoundland

FENCO NEWFOUNDLAND LIMITED
ICON BUILDING, KENMOUNT ROAD, P.O. BOX 8246, ST. JOHN'S, NEWFOUNDLAND
CANADA A1B 3N4
TELEPHONE: (709) 754-1480 • TELEX: 016-4936 • CABLE: FENCOENG

September 21, 1984

Fish Habitat Division
Gulf Area Jurisdiction
Department of Fisheries
and Oceans
Moncton, New Brunswick

Attention: Mr. Chris Morry

Dear Chris,

MINI-HYDRO STUDY FOR L'ANSE AU CLAIR

Attached is information concerning our feasibility study for a mini-hydro project at L'Anse Au Clair. This study is being performed for the L'Anse Au Clair Town Council and is co-ordinated by Energy Mines and Resources. Would you please investigate to see if it is necessary to maintain flows and provide fish ladders for this particular river system. If so, with the hydrology information that we have obtained, would you define what flows have to be maintained and at what times of the year. Any information or advise to assist the community in utilizing as much of the flow as possible would be appreciated.

As with most of these mini-hydro projects the feasibility is marginal 'without' water usage constraints. The degree of any constraints will therefore affect whether the project will proceed or not.

The earliest reply would be appreciated as a formal feasibility analysis is due by October 8 and this should include any requirements by your Department.

Thank you for your co-operation over the last couple of weeks.

Yours very truly,
Fenco Newfoundland Limited

Dale Courage

Dale Courage, B.Eng.

DC/cl

cc:
L. Davis, Project Manager
Manual Barney, Fisheries & Oceans

L'ANSE AU CLAIR HYDRO STUDY

1. LOCATION OF DEVELOPMENT SITES

- Refer to Drawing 38096-D1
- Drainage Area = 25 km^2
  - . Emptying below possible reservoir dam = 45% of drainage area
  - . Emptying above possible reservoir dam = 55% of drainage area.
- Scenario 1 - run of river - i.e., without reservoir dam
- Scenario 2 - some regulation - i.e., with reservoir dam

2. INFORMATION ON FISH TYPES

- In our field work and preliminary analyses we assumed no migratory fish in Eastern Brook as conveyed to us by local people. We were informed only small brook trout in this river. Talked to local project contact Stephen Letto extensively, talked also to one elderly resident, two members of the town council and one young person fishing further up the river by Deep Pond.
- In later discussions with Chris Morry and fisheries officer in L'Anse Au Loup, Manual Barney, we were informed that there are some sea trout which migrate up Eastern Brook.
- There is no salmon run up this river system as confirmed by fisheries personnel.

3. HYDROLOGY OF AREA

There is limited streamflow at the intake dame site due to the small drainage area. Because of the borderline evaluation of the project feasibility there obviously has to be maximum utilization of these flows. At the same time it is understood that there should be minimal threat to a major migrating fish stock.

There is no stream flow data available for Eastern Brook so data for both the Eagle River and the St. Paul's river were prorated using the drainage area ratios. The Eagle River proration gaven an annual mean of .62 m^3/s for Eastern Brook's drainage area and the St. Paul's River proration gave .59 m^3/s. Though the annual mean flows generated were fairly close the flow distribution over the twelve months were very different.

ST. PAUL'S DATA PRORATED FOR EASTERN BROOK

J	F	M	A	M	J	J	A	S	O	N	D	Mean
.19	.18	.17	.20	1.87	1.47	.55	.50	.54	.60	.47	.31	.59

EAGLE RIVER DATA PRORATED FOR EASTERN BROOK

J	F	M	A	M	J	J	A	S	O	N	D	Mean
.13	.11	.09	.15	1.52	2.26	.77	.60	.52	.64	.41	.21	.62

As can be seen the St. Paul's proration gives higher flows during winter months and the St. Paul's stream flow peaks in May whereas the Eagle River stream flow peaks in June. The St. Paul's drainage area is further south and more closely affected by the prevailing south coast climate conditions affecting L'Anse Au Clair. The St. Paul's prorated data has therefore been taken to estimate the flow distribution for the Eastern Brook drainage area.

The Hydrological Atlas of Canada (1941-1970) shows the L'Anse Au Clair area having much warmer 'Mean January Temperatures' than both the St. Paul's and Eagle River drainage areas.

For example:

L'Anse Au Clair - Contour -10 to -12.5°C
St. Paul's Draingage Area - Contour -15 to -17.5°C
Eagle River Drainage Area - Contour -15 to -17.5 and -17.5 to -20.0°C.

We would therefore expect a lesser degree of stream flow peak and an earlier spring thaw leading to an actual earlier stream flow peak for the Eastern Brook system.

Using 30 year averages for precipitation for Blanc Sablon, Cartwright and Goose Bay (on both sides but slightly further

north of the Eagle River Drainage Area), it was found that the precipitation for L'Anse Au Clair (1.160 m annual) is 22% higher than the Cartwright (.9537 m) and Goose Bay (.9461 m) mean of .9499 m. The actual total precipitation of the Eagle River Drainage Area is felt to be slightly higher than indicated by these two stations.

ESTIMATE OF EASTERN BROOK STREAM FLOW

Based on:

(i) distribution Q day/Q annual mean for St. Paul's River (15 years of data)

(ii) actual precipitation for Blanc Sablon (30 year data)

(iii) a 70% run off at Eastern Brook

J	F	M	A	M	J	J	A	S	O	N	D	Annual Mean
.20	.19	.18	.22	1.99	1.57	.59	.54	.58	.64	.50	.33	.63

An Average Daily Flow Duration Curve for Eastern Brook has been generated by our hydrology people using the 15 years of daily data for St. Paul's River and the available precipitation data for Blanc Sablon to estimate the energy potential of the Eastrn Brook/L'Anse Au Clair Development.

4 MIGRATING FISH CYCLE

Information from the fisheries office in L'Anse Au Loop gives a 'rough' idea of the timing of critical portions of the sea trout cycle.

Migration Season - Migration mid-July to mid-September.

Spawning/Winter Season - Spawning mid-October to mid-November.

Spring Season - Return to sea when ice break/thaw occurs - usually around mid-May for about a three week period.

5. PROVISIONS FOR MIGRATING FISH

If it is felt a substantial sea trout stock is threatened and the Fisheries officially requests fish ladders a mini-hydro development with storage reservoir (Scenario 2) would not be feasible. This is due to energy lost by spilling water to maintain specified flows, the cost of a fish ladder at the large dam required at Deep Pond (storage reservoir) and the cost of a fish ladder at the smaller intake dam.

A further investigation into a 'run of the river' (without storage) development would be performed using the flow that would have to be maintained as specified by the Fisheries Department.

In this case there would only be a disruption of the flows down river of the intake dam. This is only a short section of rough river (66 m drop over a 900 m run) where it is unlikely any spawning takes place. This section of the river would be considered a fish transport section which during migrating periods and sea return periods will have a required flow maintained and a fish ladder at the intake dam to allow sea trout to move upstream and downstream. Again, this is the less favourable development scenario, but if we have to go this route this is what will be presented to Energy Mines and Resources - Program Co-ordinator.

APPENDIX 7

PARALLEL GENERATION

Rates and Service Conditions

ontario hydro

Foreword

Parallel Generation - the production of electricity from sources other than those owned and operated by Ontario Hydro, is a concept of growing interest in Ontario. The forms of parallel generation are many and varied, ranging from a small windmill on a farm to industrial cogeneration. Most have one common element linking them together: the conservation of valuable purchased resources (oil and gas) through substitution with indigenous resources such as water power, wind, or through the high efficiency of fuel usage via cogeneration.

Parallel Generation in Ontario

To date, very few people or organizations have taken advantage of Ontario Hydro's offer to purchase electricity. It is hoped that by making the public aware of the rates and conditions of service available and by keeping them informed of advances in this area, customers will take a closer look at harnessing the abundant natural resources in our Province.

Ontario Hydro has established a set of rates and conditions of interconnection that offer aid and some encouragement to the private sector generator. While either Ontario Hydro or a local public utility may be the purchasing agent for privately generated electricity, this document reflects Ontario Hydro's perspective.

After reading the following information, if you require further details, please direct your enquiries to your local Supply Authority.

Types of Purchase Arrangements

1. At - Will

Under this arrangement, the utility will purchase electrical energy (kW.h) from the parallel generator without a prior committment to the amount or timing of delivery.

(i) Up To 5000 kW

In this size range, the parallel generator may sell electrical energy to the local utility having jurisdication in the area. If the utility is Ontario Hydro, the rate for at-will energy is that stated in Table I. If the utility is not Ontario Hydro, a rate for the purchase of energy will be established by the local utility.

To encourage the development of small generating facilities, Ontario Hydro will purchase at-will energy from generators in this size range within its supply area on a year-round basis.

(ii) Over 5000 kW

The current price offered by Ontario Hydro, for at-will energy with an associated capacity over 5000 kW is outlined in Table I. Ontario Hydro will purchase at-will energy for most of the year, however, there may be brief periods during the year when this form of energy has no value (for example, during spring freshet Ontario Hydro sometimes spills water over its own dams). During these periods, purchases of at-will energy in this capacity range may be limited or completely curtailed.

(iii) Metering and Administration Charges

Metering requirements are based upon the principle that:

(i) electricity delivered to the customer should be metered and billed at the appropriate retail rate; and

(ii) electricity purchased from the parallel generator will be metered appropriately for the type of contract arrangement.

In the case of at-will energy, two uni-directional kilowatt-hour meters are required, one to measure energy supplied from the utility, the other to measure energy delivered to the supply authority. The utility will supply the meter required to measure electricity delivered to the customer, at no charge just as it would for any of its customers. Metering required to monitor energy delivered from the private generator will also be supplied by the utility. However, a monthly charge will be levied to recover the added capital and to pay for the additional on-going operational expenses arising from maintenance of the additional metering equipment and processing of billing data. The administration charges for at-will energy suppliers are listed in Table I.

2. Firm Capacity

A firm capacity contract is offered only for net capacities over 50 kW. If the capacity available is greater than 50,000 kW a contract should be negotiated with Ontario Hydro to establish a suitable set of rates and service conditions. Under this arrangement, the parallel generator is given credit for both

energy (kW.h) and capacity (kW) delivered to the utility. The amount of firm capacity and a guaranteed capacity factor will be specified in a formal agreement between the parallel generator and the purchasing utility.

The rates offered by Ontario Hydro, for the purchase of firm capacity are time differentiated. They have been patterned after our proposed Time-of-Use (TOU) rate schedule that has been developed to more accurately reflect the cost of electrical generation in the rates. This schedule is presented in Table II.

Metering and Administration Charges

As described for the purchase of at-will energy, Ontario Hydro requires that the costs of additional metering and data processing be recovered through a monthly administration charge. The flow of power and energy to and from the parallel generator will be measured by use of digital demand recorders. Upgrading the metering equipment from two to four channels is normally required for firm capacity sales on the part of the vendor.

Contract Specifications for the Purchase of Firm Capacity
(for capacities greater than 50 kW)

The parallel generator offering firm capacity will be asked to specify two items in the contract: (1) Contract Capacity (kW) dedicated for sale, (2) Guaranteed Capacity Factor (%).

Guaranteed Capacity Factor (CF) is a measure of the average capacity expected to be available from the parallel generation source during times of monthly peak demand (ie, during peak hours as illustrated in table II). A different contract capacity may be specified for each season, but only one capacity factor is allowed, for instance:

Winter Contract Capacity - 150 kW
Summer Contract Capacity - 120 kW
Capacity Factor - both seasons - 90% (during peak hour periods)

Contracts for the purchase of firm capacity will have an initial term of five years; the first year will be considered a trial year. After this, the contract capacity and guaranteed capacity factor should be defined, effective for a three year period. Upon expiry of the initial five year contract, the agreement may be renewed on a yearly basis; however, the contracted capacity and guaranteed capacity factor are still renewable every three years.

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As stated above, the initial year of the contract will be treated as a trial year in which capacity payments will be pro-rated in the ratio -

$$\frac{\text{Actual CF}}{\text{1st year Guaranteed CF}}$$

subject to the ratio being no greater than unity and the guaranteed CF being set not to exceed 80%.

Where the Monthly Capacity Factor is defined as follows:

$$\text{Monthly Capacity Factor} = \frac{\text{kWh Delivered in Peak Period}}{\text{Contract kW x Peak Hours in Month}}$$

To meet the Capacity Factor guarantee in any month:

(a) The monthly CF must be at least 80% of the guarantee, and the average monthly CF for the current month and the previous 11 months must be at least 95% of the guarantee.

(b) One month per calendar year to be mutually agreed upon by all parties to the contract is allowed for planned maintenance; this month, or any month in which it is not possible for the parallel generator to provide deliveries because of problems on the utility's system, will not be included in calculation of average monthly CF as in (a).

(c) For maintenance and special months as noted in (b), if normal deliveries are possible for part of the month, the capacity payment shall be the normal payment prorated by the factor -

$$\frac{\text{Peak hours of normal delivery}}{\text{Total peak hours in the month}}$$

(assuming CF guarantee has been met during the normal delivery period).

(d) monthly capacity factor cannot exceed unity

If the guarantee is met, the monthly capacity payment will be based upon the effective capacity delivered during the month where:

$$\text{Effective Capacity (kW)} = \text{Contract Capacity (kW) guaranteed} \times \text{Capacity Factor}$$

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EXAMPLE 1:

Small Hydraulic Generation Output:

110 kW	minimum
150 kW	average
180 kW	maximum

due to variations in river flow.

Hypothetical contract aggangement:

contract kW	130 kW
guaranteed CF	90%

To receive credit for capacity under the above contractual arrangements;

(i) the monthly CF must be no less than
0.80 x 0.90 = 0.72 (ie. 72%)

(ii) the CF for the previous year including the current month must be no less than
0.95 x 0.90 = .855 (ie. 85.5%)

If the two criteria <u>are</u> met the monthly payment will be as follows:

Demand : Effective capacity = 130 kW x 90% = 117 kW
Payment for demand = TOU capacity rate x 117 kW

\+

Energy : Payment for energy = TOU energy rate x number of kW.h generated in the month

Total Payment : In the month equals the <u>sum</u> of the demand and energy payments

If the guarantee is not met for any given month, <u>no credit will be awarded for capacity</u>, however payment will be made for energy delivered as described in the section under at-will energy. (See Example 2)

EXAMPLE 2:

If conditions (i) and (ii) (as stated in example 2) are <u>not</u> met, the monthly payment will be given only for <u>energy</u> (kW.h) delivered to the system at the at-will rate

Demand : payment for demand = 0

Energy : payment for energy = At-will energy rate x number of kW.h

Total

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Payment : will be equal to energy payment only.

NOTE:

1: The Guaranteed Capacity Factor is the key to payments that will be made by the utility. Before entering into a contractual agreement with a utility, the parallel generator should carefully assess the magnitude of the CF and assign a value such that the expected payments will be maximized.

2: See appendix 1 for detailed examples of annual operations.

Technical Requirements For Parallel Generation

The requirements for protection and safe operation of parallel generators can be complex and very expensive for large capacity installations. For the smaller installations undertaken by private individuals (small wind-powered generators, hydraulic plants), costs should not be as great. The general requirements are:

1. A means of synchronizing the generator and the power system;

2. a circuit breaker between the generation and the power system, with adequate interrupting capacity to clear all faults on either side of the breaker;

3. generator overload protection;

4. provision for automatic disconnection of the generation from the power system in the event of an outage of the power system supply;

5. provision for isolation of the generator from the power system in the event of unsatisfactory generator voltage or frequency;

6. a visible, manual disconnect switch close to the point of interconnection of the generator and the power system to provide utility maintenance crews with a means of isolating the generator when work on power system equipment is necessary;

7. all equipment must be CSA approved and installed in accordance with the Electrical Safety Code;

8. all equipment must be designed to avoid damage from over-voltage or automatic reclosure operations on the power system; and

9. the harmonic content of the generator output must be within acceptable limits.

To guarantee the safety of all parties, an operating agreement is required which would specify all procedures required for safe operation of both the supply system and the parallel generator. These procedures enable Ontario Hydro to exercise control (where applicable) over the electricity flow from any private generation site. To guard against backfeed from a parallel generator during maintenance of the supply system, Ontario Hydro will maintain Operating Control of the device connecting the private generator to the power system (usually an externally mounted circuit breaker).

Special Costs Borne by Generator

The point of delivery for a parallel generator is located at the point of attachment nearest to the parallel generator's property line. The voltage from a parallel generator source will be at the appropriate supply voltage of the power system. Parallel generators interconnected at voltages above 50 kV will be asked to satisfy all applicable conditions outlined in the policy document "Supply Conditions for Customer-owned Facilities Supplied by Ontario Hydro at Voltages above 50 kV", June 1980. Further information is available upon request.

Modifications arising from the need to make physical connection between the point of delivery and the appropriate distribution line will be performed by the supply authority. The parallel generator will be requested to make a capital contribution to cover the cost of these changes over and above the cost of changes justified by revenue anticipated from power sales to the parallel generator.

Modifications to the power system needed to ensure equipment protection and safe operation, arising from the connection of the parallel generator will be undertaken by Ontario Hydro, and the expenses will be covered by a capital contribution from the parallel generator. However, where these modifications are of mutual benefit to the generator and the power system, these costs will be shared by the two parties.

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TABLE I

Energy Rate and Administration Charges for "At Will" Energy
(With Capacities up to 5000 kW)

Energy Rate

16.1 mills per kW.h

Administration Charges to Parallel Generators

If additional single phase kW.h metering required	$ 6.25/month
If additional three phase kW.h metering required	$ 12.50/month

Effective date: January 1, 1982

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TABLE II

Schedule I

Provisional Rates for Purchase of Firm Capacities Between 50 kW and 50,000 kW

Capacity Rates

Winter	$4.28 per effective capacity (kW)* per month
Summer	$2.35 per effective kW* per month

* Effective capacity (kW) to be determined as the product of guaranteed capacity (kW) and the guaranteed capacity factor for delivery during the peak hours of each month.

Energy Rates

Winter Peak	18.0 mills per kW.h
Winter Off-Peak	16.1 mills per kW.h
Summer Peak	15.5 mills per kW.h
Summer Off-Peak	12.7 mills per kW.h

Administration Charges to Parallel Generators

If 4 channel digital metering required	$138/month
If upgrading from 2 to 4 channel digital metering required	$ 49/month

Time of Use

Winter	- September through March
Summer	- April through August
Peak	- 7 am to 11 pm, weekdays
Off-Peak	- 11 pm to 7 am, weekdays plus all weekends and public holidays

Effective date: January 1, 1982

APPENDIX I

Sample Calculations for Examples 1 and 2

	Number Of Hours	Number Of Hours During Peak Period	Total Energy Delivered (kW.h)	Energy Delivered During Peak Period (kW.h)	Monthly Capacity Factor (%)	12 Month Capacity Factor (%)	Capacity Payment ($)	Peak Energy Payment ($)	Off-peak Energy Payment ($)	At-will Energy Payment $)	Total Payment ($)
Jan.	744	320	112,250	47,100	98.1	-	642	848.00	1,049.00	-	2,539.00
Feb.	672	320	103,500	46,300	96.5	-	642	833.00	921.00	-	2,396.00
Mar.	744	368	113,700	51,700	93.7	-	642	931.00	998.00	-	2,571.00
April	720	320	124,600	51,300	133.6	-	282	795.00	931.00	-	2,008.00
May	744	320	131,100	52,400	136.5	-	282	812.00	999.00	-	2,093.00
June	720	352	99,500	41,600	98.5	-	282	645.00	735.00	-	1,662.00
July	744	336	80,700	32,400	80.4	-	282	502.00	613.00	-	1,397.00
Aug.	744	336	75,600	31,100	77.1	-	272	482.00	565.00	-	1,319.00
Sept.	720	336	-	-	-	-	-	-	-	-	-
Oct.	744	320	102,000	41,800	87.1	-	642	752.00	969.00	-	2,363.00
Nov.	720	352	107,800	47,700	90.3	-	642	859.00	968.00	-	2,469.00
Dec.	744	336	112,400	46,900	93.1	-	642	844.00	1,054.00	-	2,540.00
Jan.	744	336	109,600	45,500	90.3	98.0	642	819.00	1,032.00	-	2,493.00
Feb.	672	320	95,400	42,400	88.3	97.2	642	763.00	853.00	-	2,258.00
March	744	368	88,300	36,100	65.4	94.6	0	0	0	1,422.00	1,422.00
April	720	304	105,200	42,900	117.6	93.1	282	665.00	791.00	-	1,738.00
May	744	336	112,300	49,700	123.3	91.9	282	770.00	795.00	-	1,847.00